Report of the Advisory Group on Demand-Side Management and Demand Response in Ontario

in Response to the Minister's Directive to the Ontario Energy Board

December 12, 2003

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1 INTRODUCTION

On June 18, 2003, the Ontario Energy Board (Board) received a directive from the Minister of Energy (Minister) directing the Board to consult with stakeholders to identify and review options for the delivery of demand-side management (DSM) and demand response (DR) activities within the electricity sector, including the role of the local distribution companies (distributors) in such activities. The directive includes reference to the potential role of local aggregators within markets administered by the Independent Electricity Market Operator (IMO). Subsequently, the Board expanded the scope of the review to include the role of gas distributors in DSM.

The Board received expressions of interest from 118 stakeholders in response to an invitation to participate in this process. Of these, 31 representatives from all sectors (electricity generators and distributors; gas distributors; industrial, commercial and residential energy user groups; energy service providers; metering and control technology companies; non-governmental organizations (NGOs); and the IMO) were invited to participate on an advisory working group (Group) to develop options for the Board's consideration in preparing its recommendations to the Minister. Lists of stakeholder organizations, presentations and written representations received and Group membership are available on the Board's web site (www.oeb.gov.on.ca). Board staff prepared a discussion paper Demand -Side Management and Demand Response in the Ontario Energy Sector as background for the advisory group.

The Group held 14 full-day meetings between October 22 and December 9, 2003. Two Board staff and an independent facilitator assisted the Group in its deliberations. On the first day, the Group discussed its mandate and how it would structure its deliberations over the coming weeks. An important decision reached in this discussion, was that the Group would make an effort to rise above individual stakeholder interests (which would be evident from the stakeholder written representations) and attempt to present generic options to the Board, identifying advantages and disadvantages of each without taking an advocacy role in favour of one or the other.

This report is a consolidation of the Group's working documents and represents the results of deliberations both as a unit and in small groups. This document does not imply a complete consensus of views among Group members. Options are put forward on a without prejudice basis. Individual Group members may take positions in the future that differ from those expressed in this document.

Two days were devoted to hearing oral presentations from 14 stakeholders. The Group also had available 28 written representations from stakeholders and received a presentation on DR from the IMO. A representative of the Ministry of Energy was also available as a resource to the Group throughout the process.

In subsequent deliberations, the Group discussed the market foundations currently in effect, and how these might be altered to better support objectives that would otherwise have to be met through formal DSM and DR. Market issues also surfaced frequently during later discussions, particularly when DR was discussed. The result of these discussions is found in the section titled Market Issues.

DSM models and the DR framework were the focus of deliberations during the subsequent eight days. The Group approached the topics of DSM and DR by dividing itself into self-selected sub-groups to prepare written summaries of a DR framework and DSM model options and then reporting back to the Group in plenary to further discuss and refine the framework and models. Initially, four DSM models were considered. Given the reference to the role of Local Distribution Companies (LDCs), one obvious model to consider was that LDCs take responsibility for the design, development and delivery of DSM. This became known as the OEB/Wires Model.

The other DSM models evolved from the recognition that, if the LDCs were not the agents responsible for DSM, and in the absence of sufficient DSM occurring in the market at present, another agency would be required to promote, design and deliver DSM programs. These models became known as the Central Agency models. Initially, three Central Agency Models were considered. The primary difference among them was the extent to which the Central Agency took responsibility for identifying DSM opportunities in the market and designing and delivering the programs, as opposed to contracting these functions out to either a single Energy Efficiency Utility (akin to the Vermont model), or to a full range of market participants, load aggregators or other agents through a competitive bidding process. As these models were further developed, it became apparent to the Group that the best way to present them was as a single Central Agency model with variations as to the role of the Central Agency and other players in the electricity market.

The final three days were spent refining the work of the sub-groups and crafting it into a coherent package suitable for the Board's consideration. Accordingly, in addition to the Market Issues section, this report includes sections on a DR Framework, an OEB/Wires Model for DSM and a Central Agency DSM Model.

It is important to note the models that we present herein were developed with a focus on the electricity sector. While many of the features may be applicable to gas DSM it should not be presumed that the advisory group had so concluded. The central agency delivery models lend themselves to a multi-fuel approach but can co-exist with separate gas LDC DSM portfolio management. The LDC based model implies the maintenance of the role of the gas LDCs as the primary gas DSM portfolio managers. The central agency models could also be implemented for electricity at first with consideration of merging gas DSM into such a model being deferred until a track record is available.

Late in the course of the Advisory Group's deliberations the Minister of Energy introduced new legislation and sent a strong message on conservation[1]. In the

[1] See backgrounder entitled “Ontario Energy Board Amendment Act Highlights Of The Proposed Changes” that accompanied November 25, 2003 “Ontario Government Takes Responsible Action On Electricity Pricing” news release by the Minister of Energy (www.energy.gov.on.ca).

backgrounder to the news release, among other matters, the Minister announced that the Board will be directed to provide for an increase in distribution rates to provide for the third phase of the move to a full market-based rate of return. This is to be conditional on the distributors investing one year's worth of this increased revenue into conservation and demand management initiatives. At the time of this writing, the bill has not yet been passed and specifics have not been announced. However, the Advisory Group wishes to alert the Board and the Minister to concerns that some Group members have regarding the announcement.

It has been estimated that this announcement could mean that more than $200 million may be made available for investment in conservation and demand side initiatives. The Advisory Group recommends that a framework be established within which these initiatives would be developed and delivered, prior to the money being invested by the LDCs to ensure that it is spent in the most cost-effective manner.

The Government has sought the advice of the OEB regarding its views as to the appropriate framework within which to facilitate DSM and Demand Response initiatives. The Advisory Group work has been to inform the Board's process to develop recommendations for that framework. Some members of the Advisory Group urge the Board to indicate to the Government as soon as possible that the DSM and DR spending envisioned in the Minister's announcement should be assisted by the OEB's views as to the appropriate DSM/DR framework for Ontario's energy sectors.

2 MARKET ISSUES

This section presents the results of discussions of shortcomings or failures in the Ontario energy market (primarily in electricity, but also in natural gas) that can be addressed by three general sets of actors:

- Government — particularly the Ontario government and the federal government;
- The IMO as operator and rule-maker of the (IMO-administrated) wholesale electricity market; and
- The O.E.B. as regulator and rule-maker of the remainder of the electricity and gas markets.

These discussions address both the failures and the potential "repairs" of those failures — some of which were very broadly supported, while others were more controversial.

In subsequent sections, we will present the results of our discussions of specific competing models for the delivery of Demand-Side Management (DSM) activities, with pros and cons of each, and a general framework for the delivery of Demand Response (DR) activities. But first, it is important to establish the relationship of the Market Issues recommendations to both DSM and DR.

2.1 Market Issues and Demand-Side Management (DSM)

In the academic and regulatory literature, and in this Advisory Group, the standard justification for conservation programs funded by surcharges or taxes on non-participants – DSM programs – invokes "market failures". These market failures are imperfections in the market that prevent energy market participants — *e.g.*, from electricity generators to end-users — from making optimal decisions. In that context, most participants considered it logical and beneficial to examine those market failures, and to recommend the elimination or repair of those failures wherever possible, as a "threshold issue".

Among the members of the Advisory Group, there was a wide range of views on the relative weight to be given to the two general responses to market failures that increase energy consumption above optimum levels:

- repairing the flaws in the market, to give all participants better tools and inputs to their decisions – information, price signals, market power, etc.; or
- instituting marketplace interventions — DSM activities — to help end-users approximate the decisions (primarily capital spending decisions) that experts believe that they would have made with "perfect" information and price signals.

In the view of the strongest proponents of market issues activities, “market repair” can be generally expected to produce results that are more efficient, productive, and flexible than DSM activities. Moreover, in the extreme view, there is no functioning competitive market in the world that could not theoretically be improved with the help of state or monopoly intervention guided by well-intentioned experts — yet those markets that have been the most aggressively "improved" with the help of such interventions have most often produced disappointing results or collapsed, while more "imperfect" markets have created enormous total wealth and incredible rates of advancement.

In the view of the strongest supporters of DSM activities, the many imbalances between the supply side and the demand side in the regulated monopoly energy marketplace demand market intervention in the form of DSM programs, and will continue to do so even after the energy marketplace is "perfected". Furthermore, in this view, it is unrealistic to expect governments to stop subsidizing energy supply projects in the near future, or to expect the many other artificial market failures to be repaired "in the real world".

Despite this wide range of viewpoints, there was overwhelming support for both responses. All or virtually all participants agreed on the desirability of making repairs to the marketplace, and agreed that any conceivable marketplace repair would still leave a gap between actual consumption levels and theoretically cost-effective or "least-cost" consumption levels — a gap that can be addressed with DSM activities.

2.2 Market Issues and Demand Response (DR)

Correcting market issues is generally more synergistic and less conflicting with Demand Response activities than they are with Demand-Side Management activities, although the situation is a bit more complex. For example, since the present electricity market framework does not appropriately reward Local Distribution Companies (LDCs) for cutting their own peak demand, improving the rules in that framework is arguably a necessary condition of enhanced DR activities by LDCs, rather than a threshold issue that solves the same problem more flexibly and thereby competes with those activities. On the other hand, proposals that increase the retail price of end-use consumption, especially when the electricity system is unusually stressed (or when the market-clearing price is unusually high), can be seen as addressing the same problem that the Advisory Group's proposed DR activities (presented in a later section of this report) are designed to address, and therefore generally compete with those activities. Furthermore, some of the Advisory Group's proposed DR activities can themselves be seen as "market repair" activities, because they introduce voluntary and flexible demand-side market mechanisms to enable end-users to participate in an energy marketplace that now treats most of them as captive, passive consumers.

2.3 The Role of Efficiency Standards

Government-imposed minimum efficiency standards can be seen as the most extreme of DSM measures — after all, they forbid every person and business in Ontario to purchase equipment below a certain efficiency level, regardless of individual preferences, values, or situations — and yet these standards enjoyed great support among the members of the Advisory Group. In essence, where it was felt that a majority of Ontarians would choose to purchase equipment above a certain efficiency level *if* they spent time and effort to consider the alternatives, the benefits (i.e., increased energy efficiency, decreased consumer regrets, and decreased transaction costs) were seen to outweigh the costs (i.e., loss of choice -- freedom to choose a less efficient, and presumably cheaper option). Of course, the choice of where to set the minimum legal efficiency level is very important, and one that was not discussed in our deliberations and might well have generated significant controversy if it had been.

2.4 The Role of Labeling and Information

A similar "market issue" that arose from time to time but was not directly addressed in detail is the issue of energy-efficiency (or energy-consumption) labeling and information. Recent developments in the marketplace like the Energy Star program, Energuide, and Ecologo program have all helped repair certain segments of the energy marketplace, while others seem cloaked in confusion or even "false or misleading" claims — an acknowledged area for provincial government activity in Canada. For example, ordinary consumers faced with on-the-shelf claims of "high efficiency" for electric resistance heaters, or electric domestic hot water heaters, could assume that those devices were environmentally more benign and more economical to operate than their natural-gas-fired alternatives — while most or all Advisory Group members were apparently convinced otherwise. Similarly, if the bewildering array of information about "watts" and "candle-power" on light bulb packages were replaced with a simpler system, consumers might shift demand significantly from the least efficient bulbs (long-life incandescents) to the most efficient (compact fluorescents).

Although individuals might have strong preferences for specific labeling approaches, the improvement of consumer information is generally seen as a “market repair” mechanism with very low costs and virtually no unintended negative consequences.

2.5 Preliminary Analysis and Findings

In the following sections discussing three general groups of market failures and “market repairs”, the Advisory Group considered six general over-arching questions for each failure and its repair:

1. What is the problem and how is evident?
2. What are its potential causes?
3. If legislation, market rules or regulatory instruments contribute to the causes, what are they?
4. Can a foundation change fix it? If so, what is the change?
5. What might be the unintended consequences of making the change?
6. Are any subsequent changes required?

2.5.1 “Market Repair” by Government through Legislation and Regulation

Treatment of Demand-Side and Supply-Side Resources

- Evidence of Problem: There are tax and other incentives to the supply side that have no parallels on the demand side, leading to excessive supply and less-than-optimal demand-side efficiencies.

- Possible Causes: Public ownership (OPG; etc.); Lack of financial disclosure; Lack of internalization of external costs; including environmental harm; Special or temporary incentives and subsidies become institutionalized and can't be discontinued.

- "Foundation" Solutions: Sell or at least subject to commercial discipline; Force full financial disclosure; Internalize external costs, including environmental harm; "Sunset" all special or temporary incentives and subsidies.

- Unintended consequences or drawbacks: Lack of political support; especially for selling OPG and Hydro One assets and perhaps for internalizing external costs; including environmental harm.

Much of the Advisory Group's discussion focussed on the electricity marketplace and ignored gas, which also bears a number of particular market barriers and imperfections in the governmental or "legislation" arena. For example, the following were included in one of the initial presentations made to the Group. Note that all of these are primarily under the Federal Government's control, but they should presumably still be brought to the attention of the OEB and the Ontario Minister as barriers to DSM and DR and efficient allocation of resources in Ontario:

- tax incentives for gas exploitation, *e.g.* flow-through shares and accelerated depreciation allowances for gas production investments (Note that the US federal government has similar programs. Canadian tax rules require ground source heat pumps to use a 25-year depreciation rate whereas some gas wells are allowed 3 years.)
- expropriation rights for pipelines, administered through NEB;
- absence of pollution cost internalization for polluters (also applies to provincial government)

For these market flaws, one set of "Foundation" Solutions would be, obviously, to remove those special advantages to energy supply:

- Subject the gas-exploration industry to the same tax rules that govern most other sectors of our society and economy;
- eliminate (or at least diminish) expropriation rights for gas pipelines; and
- internalize pollution costs for all polluters, including energy supply, transport, and consumption.

Some of these "Foundation" Solutions – perhaps especially the elimination or diminution of expropriation rights for gas pipelines — would likely create unintended consequences that need to be examined and discussed, but have not been in our meetings.

Artificial Pricing

A Evidence of Problem: Bill 210 — Fixed Price at 4.3 ¢/kwh

A Possible Causes: Market brought price volatility; Ineffectiveness of Regulation; Past political price freezes brought expectations of price stability; Simultaneous introduction of unbundling added confusion; Prices stayed high one month too long (September)!; Political Panic; Residential Retail Marketers brought "education" that wasn't all helpful

A "Foundation" Solutions include the following. Note that this list incorporates over-arching questions 4, 5 and 6 of section 2.5 – *i.e.*, the pricing proposals here are pre-compromised, to address the unintended consequences of a more "pure" foundation solution, like real-time variable pricing, tracking actual costs.

- Rates that track costs more closely — yet are politically tenable,
- Lifeline Rates (<250 kwh) = "inverted block rate structure" with a first block of energy at a low (perhaps even below-cost) price, and subsequent energy at a higher — above-cost — price.
- Can be seasonally differentiated, perhaps along the lines of the gas industry's Quarterly Rate Adjustment Mechanism (QRAM), which would give a periodic true-up mechanism that could correspond well with four seasons — Summer and Winter "peak" vs. Spring and Fall "off-peak".
- A robust and competitive retail market — but NB that the market for supply to large retail is healthy and competitive.
- Day-ahead "future" market for price predictability (wholesale and large retail)

OPG Market Power

A Evidence of Problem: OPG share of the marketplace

A Possible Causes (and impacts/problems): Stranded debt issues; No incentive to attract new generators; Lack of liquidity in the marketplace; Creates Market uncertainty; Government acts as OPG shareholder

A “Foundation” Solutions: Decontrol or capacity auction; Market Power Mitigation Agreement — changes to accelerate decontrol; NB: this is also (maybe even more) a "Market Rules" and "Regulation" issue; divide the old Ontario Hydro's generation assets into several competing units as considered by the Market Design Committee; Cap taxpayer-supported debt by enforcing OPG payments to OEFC, rather than diverting funds to Pickering-A restart; market bias toward supply solutions — there is now no public recognition of DSM benefits

Raising Capital Costs through Energy Savings

- Evidence of Problem: The "MUSH" sector — Municipal, University, Schools, and Hospitals — has a perverse incentive structure: Investments to save energy must be justified out of scanty "capital" budgets, while energy costs are automatically paid out of annual "operating" budgets. Furthermore, any operating savings are "clawed back" in a spend-it-or-lose-it budget system.

- Possible Causes: History — it's the way it's always been done; Spend it or you lose it; No reward for reducing usage or improving efficiency; No standards; Overemphasis on first cost vs. life-cycle cost; Landlord/tenant split incentives in leased facilities tenant pays but does not own, landlord owns but does not pay.

- "Foundation" Solutions: Multi-year financing; Education of CFOs; Life-cycle approach to investments; "Performance-based regulation" (PBR) for MUSH; IRP approach, integrating and equating demand and supply side; MUSH funding like "Consolidated Revenue Fund", so savings are retained; Ministry of Infrastructure Renewal may be able to address this barrier; Establish a "bootstrap" fund, like the Toronto Atmospheric Fund (TAF) (this may be "DSM" rather than "market repair"); Establish strong minimum energy-efficiency standards for MUSH sector investments

2.5.2 "Market Repair" by the IMO through Market Rules

Retail customer DR is not valued in the IMO market

- Evidence of Problem: Customers not exposed to retail prices (<250,000 kWh/a); Self-evident - water heater controls abandoned, lack of adequate response to appeals for conservation;

- Possible Causes: Fixed price legislation; Fixed price contracts (immature market didn't allow product/customer differentiation); evident in metering technology); No incentive - for customers, LDCs, retailers; LDCs not allowed ROE on DR assets/investments; price inelasticity of consumers

- "Foundation" Solutions: Enable aggregators to participate in IMO market including OR market; Enable retail customers to opt in to market pricing without necessarily becoming IMO market participants; Enable LDCs (or other, e.g., retailer) to become load aggregators for (standard supply or retail contract) distribution service customers for DR aggregation (not necessarily include energy procurement); need to consider transaction costs, i.e., customer acquisition costs for DR, may be high relative to potential for DR pay-off; Create economic DR program (paying load to go away), perhaps as a transitional measure only (training wheels)

- Concerns: Concern about distributors being able to compete with non-regulated; some argue that LDCs should be allowed a role; some argue that private sector can deliver more effectively

- Potential Unintended Consequences: Inequity between wholesale and large retail customers if relax rules for retail. Settlement and audit burden if different rules for retail vs. wholesale.

Forward price uncertainty inhibits DR

- Evidence of Problem: HADL (Hour Ahead Dispatchable Load program initiated by the IMO) has had limited uptake. AMPCO view that HADL is nice but not sufficient. Doesn't compensate for start-up costs or guarantee minimum run times. Large commercials have investigated but taken little action.

- Possible Causes: Poor correlation between dispatch and pre-dispatch. Insufficient advance notice for DR. Uncertainty of price duration for DR. Economics seems to be unclear; revenues insufficient.

- Contributing factors: Still problems with market transparency and confidentiality about what's happening in the market, e.g., compared to Alberta which releases close to real time information on generation and outages.

- Solution: Day-ahead market; economic DR program; increase HADL to, for example, 4 hours ahead for a 4 hour window and allow large retail to participate in DL program; seasonal time of use rates.

- Potential Unintended Consequences: Options could be conflicting or mutually exclusive. Solutions could yield inefficient or sub-optimal market outcomes. Other pre-requisites, e.g., LMP needed for DAM.

Inefficient pricing (lack of price transparency) undermines efficient DSM/DR

- Evidence of Problem: Implementation of initiatives to reduce price volatility and price uncertainty affect the price transparency, e.g., IOG in uplift, 12 x ramp rate, out of market control action, spare generation on-line; counter-intuitive pricing; variance between pre-dispatch and dispatch; uniform pricing not-reflective of economically efficient cost of power at specific locations; high prices for imports (guaranteed) but no equivalent guarantee for DR, lack of overall confidence and investment in the market.

- Possible Causes: Market rules, e.g., IOG, SGOL, etc.; market power; uncertain amount of MPMA rebate obscures true price; political intervention.

- “Foundation” Solutions: IMO Market Evolution Program (e.g., pricing initiative); borrow from IOG concept to 'guarantee' DR; reduce political intervention; proceed with decontrol or otherwise address market power

- Potential Unintended Consequences: Potentially higher prices and increased volatility; lack of public and political acceptance. Note that efficient pricing alone may not achieve the level of DSM that would be desired considering full costs, externalities and collateral benefits.

2.5.3 “Market Repair” by the Ontario Energy Board through Regulatory Instruments

Transmission rate structure

- Evidence of Problem: no geographic price differentiation

- Possible Causes: past regulation, rules, market design issue

- “Foundation” Solutions: different tariff rate for transmission geographically

- Potential Unintended Consequences: This is a move away from postage stamp rates that could have broad social impacts that would require consideration prior to such a change.

Retail Rates and Metering

- Evidence of Problem: Lack of price signal transparency for smaller retail customers means less than optimal EE investment; no location differentiation in distribution or commodity charges; no time differentiation in distribution or commodity charges; differentiated (time and, if implemented, location), capacity based transmission charges not passed through to small customers on that basis, therefore they have an inaccurate price signal; there is uneven treatment of loads utilizing embedded generation (i.e. those with on site generation avoid transmission charges under the RP-1999-0044 decision, whereas users of off site LDC embedded generation see no price signal that reflects any transmission savings that may result)

- Possible Causes: past regulation, rules; lack of metering

- “Foundation” Solutions: need mechanism for holistic cost/benefit analysis; regulation should enable time differentiated rates and interval meters for customers (even small); competitive market should decide what is the most cost effective solution - with proper pricing and metering retailers can offer differentiated rates also other service providers could offer innovative services - ex ESCO/retailer partnerships; rule changes by OEB; LMP (eventually) and peak differentiation in all charges; policies and rules around transmission charges associated with use of LDC embedded generation should be reviewed to ensure uniform and appropriate treatment

- Potential Unintended Consequences: the cost to provide RTP (real time pricing) to small customers may be prohibitive, not worth benefit; small customers may not understand more complicated price structures (e.g. capacity, spot prices); self selection for voluntary metering can lead to inequities if the rate structure is not kept cost based; metering, billing and other infrastructure enhancements required may not be justified by the benefits obtained for every customer segment in every distribution territory - a proper cost/benefit analysis is required; this is a "user pay" approach, potentially extending down to the smallest customer, some of whom have the least ability to pay. This may place unintended hardship on a group of customers. User pay is fundamentally different than the current socialized (i.e. averaged) cost structure that is in place for transmission, for distribution within a service territory (and with respect to rural rate assistance) and, depending on the rate structure, commodity as well. This a fundamental philosophical discussion that needs to take place at the political/legislative level first and the decisions taken there should flow through the market rules and regulatory framework, rather than the other way around or there could be significant unintended consequences.

- Subsequent considerations: depending on the outcome from the philosophical discussion referred to above, social assistance, rural rate assistance, and perhaps other programs may need to be restructured in some manner

EE and system optimization alternatives to wires and losses

- Evidence of Problem: no incentive to improve system losses for wires companies (LDCs and transmission companies); LDCs and Transmission companies have no incentive to consider energy efficiency investment in lieu of wires investment (no ROR on EE investments); Although EE could delay or displace capital investment, this should be evaluated on an equal footing with supply side options (LIRP Local Integrated Resource Planning). LDCs do system augmentation planning on 10 yr horizons for capacity needs, but don't implement until crisis is reached at which point it’s too late to consider EE alternatives

- Possible Causes: PBR doesn't provide incentives; LDCs can't invest in EE and earn a return

- “Foundation” Solutions: distribution losses should be part of LDC PBR; transmission losses should be part of transmission PBR; change price structure to reflect peak losses to end customers (i.e. time differentiated losses); holistic (IRP) analysis for wires investments; LDCs should earn a return on efficiency as they do on wires investment (there is debate re whether LDCs should act as EE delivery agent as opposed to LDC EE planning and investment - i.e. when they decide to invest in EE they should be required to contract it out)

- Potential Unintended Consequences: Passing through peak loss pricing may be too complex for the benefit gained

DSM measures erode LDC revenue

- Evidence of Problem: LDCs have disincentive for their own conservation efforts and for cooperating with others; EE erodes revenue in price cap PBR

- Possible Causes: Regulatory choice - Price Cap PBR; distribution rate structure and retail transmission rate structure (mostly volumetric) are not aligned with the cost structure (mostly fixed - i.e. capacity based)

- “Foundation” Solutions: (gross) revenue cap per customer in the long term - under this structure wires company is shielded from EE revenue erosion and is protected from others EE and risk due to weather; short term - variance accounts; alternative would be to collect retail distribution and transmission charges based on capacity or a fixed customer charge

- Potential Unintended Consequences: under revenue cap distribution rates are less stable for customers due to periodic adjustments; capacity based or fixed customer charges are not politically acceptable and have implementation and rate impact problems

No Role for DR Aggregators

- Evidence of Problem: small end users can't play in the IMO market to reduce peak demand and lower system cost; LDC water heater control assets are not being effectively utilized

- Possible Causes: no mechanism for aggregator, such as a LDC, to enable this; retailers and LDC retail affiliates (regulated LDC is precluded) can act as aggregator but there are no rules and is no market for this service now with the price cap; Limits on LDC role restrict synergistic efforts (e.g. Water heater rentals and load control)

- “Foundation” Solutions: Metering, pricing, rate structure improvements will create market for the DR aggregator business; LDCs (as opposed to their retail affiliates) should be able to be DR aggregators due to possible economies of scope or scale - HOWEVER there is debate on this point, some think LDCs should not compete with private sector in the competitive part of these services - some private sector companies can provide these services to certain parts of the market

- Potential Unintended Consequences: regulated LDCs and their unregulated affiliates are precluded under the affiliate relationships code from sharing customer information. It may be difficult to limit this sharing of customer information only to DR activities.

3 DEMAND RESPONSE FRAMEWORK OPTION

3.1 Overview

The Minister's directive requires that the Ontario Energy Board (OEB) consult with stakeholders to identify and review options for delivery of demand side management and demand response activities in the electricity sector. In conducting the review the OEB was directed to examine the potential role of local distribution companies, retailers, and other market participants as load aggregators within the IMO administered markets.

This section specifically addresses the demand response portion of the Minister's directive, and the associated role of aggregators.

For the purpose of discussion, demand response was segmented into three types:

- *Natural Demand Response* to price with no additional compensation. This includes Time-of-Use rates and critical peak pricing.
- *Economic*[2] *Demand Response* involves compensation or incentive to a load responding to price signal.
- *Emergency Demand Response* is, as the name implies, used only in system emergency situations and was not discussed.

We begin from the premise that markets should operate to the benefit of consumers and that a market does not operate efficiently if consumers are not responding to price. Large Industrial (wholesale) consumers have demonstrated very limited ability to respond to price signals in the current market. They have expressed the need for greater guarantees and compensation to implement changes in production.

Large Commercial consumers, while not wholesale consumers, still receive the Hourly Ontario Electric Price (the spot market price pass through). Again, very little if any demand response capability has been demonstrated, due to inability to respond with such short notice, lack of price certainty, and uncertain returns.

Small consumers, including residential, effectively have no motivation to respond to price signals as they currently have their energy price fixed, below true market costs.

2 Although usage of this term is common in the trade, several participants objected to its normative implication that side payments for DR are always economically efficient or economically justified – and that "natural" DR is not economic. Neither implication was widely supported by Advisory Group members.

Demand response is required in both the retail and wholesale markets. Customers in both markets should be enabled to respond to price. In a well functioning market ***all*** consumers would be exposed to price signals of some type and would be able to adjust their consumption according to their preferences and self-interests.

In the absence of such 'Natural' customer response to price, economic demand response programs are advocated, at least on a temporary or transitional basis, to stimulate demand response and develop capability.

The following framework outlines an option for the delivery of such *economic demand response* programs, assuming settlement through the IMO administered markets.

3.2 Background – Objectives for Demand Response

The Advisory Group reflected the strong and often divergent viewpoints already evident in the market regarding the objectives of Demand Response.

Many members argued that *reduction of energy costs* for all consumers was the primary objective of Demand Response. By having *some* consumers reduce demand during times of supply shortage, market prices are reduced for *all* consumers (the so called collateral effect). This can be viewed as a transfer of wealth from generators to consumers. Consistent with this is the position that reducing demand by 'X' MW is fully equivalent to supplying 'X' MW of generation, and should be compensated accordingly. (i.e. *economic* demand response)

The opposing view, also expressed by members, is that the objective for demand response should be *to achieve 'correct' or 'efficient' pricing*, not necessarily lower pricing. Payments for loads to *not* consume is an artificial subsidy that provides incorrect market signals. It is seen as aggressive market intervention that will further discourage needed investment in new generation supply. Also, DR is not fully equivalent to new supply, as it cannot provide sustained capacity reductions.

These two divergent views are more fully articulated in the 'Policy Considerations' section of this paper (Section 3.6).

Consensus *was* achieved around the objective of *enabling consumers to participate in the market*. This was seen as providing greater market liquidity and efficiency, and equity amongst consumers. Economic Demand Response was seen as a transitional means of *developing the capability for consumers to respond to prices* and was endorsed on this basis.

The valuation of Demand Response benefits, and associated screening of DR options, was similarly polarized according to the professed objective for DR. The application of a TRC test, consistent with DSM measures, was argued as being valid where the stated objective for DR was a reduction in energy prices. If the overall policy objective is lowering the market clearing price, then the net reduction in customer bills is an appropriate measure, but is not considered an avoided cost (it is a transfer of wealth). Given the objective of *enabling consumers to participate in the market,* the valuation of DR was seen as more qualitative, with a limit as to the extent of participation that was necessary. Evidence of 'Natural' DR occurring, with participation of all customers classes, was generally considered to be a measure of success.

Framework for (Transitional) Economic Demand Response.

In this model the IMO settles and administers payments to consumers in the wholesale market. Wholesale consumers, by definition, are market participants with an established commercial relationship with the IMO.

Retail consumers would transact with the IMO through (or as) an 'Aggregator'. The Aggregator would be a new class of wholesale market participant that represents Retail market consumers.

In this model the Aggregators and the existing Wholesale Consumers represent a 'competitive market' for DR, each offering their unique capabilities and competing choices for curtailment of load at a given price.

3.3 Roles And Responsibilities

DR roles would vary according to whether or not DSM/DR activities were managed using a Wires/LDC model or a variant of a central agency model. In either approach (LDC or central agency) the question of whether LDCs could or should act as private load aggregators remains open. In addition each approach must provide for activities to enable DR, to avoid local transmission congestion, to enable private DR for profit and to enable DR as a public benefit in instances where private DR might not be profitable but where it would be unsound to forego additional DR benefits.

3.3.1 Government/Minister

- Set Demand Response Policy. Confirm that the development of demand response capabilities is necessary to the proper functioning of the market.
- Confirm the extent to which/what type of demand response there will be. I.e. transitional economic DR, representation by different market sectors.
- Incentives for DR enabling equipment (tax incentives, grants, loans or other funding mechanisms), as there are for new generation investment.

3.3.2 OEB

- May require development of new class of market participant with regulated obligations for a load aggregator.
  - May require a variant on electricity retailer license to deal with consumer protection and conduct matters

- – Existing licences may accommodate the participation of load aggregators in the IMO administered markets
  - > The Board may need to amend licence obligations of retailers, wholesalers, transmitters and distributors to accommodate load aggregation function (prudential requirements, access to and use of consumer information, settlement related obligations)
- Require LDCs to respond in a set time to requests for interval meter installations.
- Approve meter installation rates that are comparable across LDCs (reasonable), not subsidized
- Ensure ready access to customer meter data for aggregators.
- Approval for time differentiated or DR enabling rates.
- Allow LDCs to act as aggregator (the advisory group did not discuss in detail).

3.3.3 Central Agency

- Develop/promote initiatives focused on overcoming barriers to demand response.
- Economic demand response targets are different from those considered as natural and if funding for an economic demand response program is provided through a system benefit or DSM charge – set targets for demand response programs.

Note that ‘Natural’ DR activities such as regulated rates, customer information, technology and opportunity assessment, could be addressed in the same manner as DSM.

3.3.4 IMO

- Implement Minister’s policy within the objects of the IMO under the Energy Act and the jurisdiction of the IMO.
- Allow / investigate non-dispatchable and aggregated loads to participate in Operating Reserve markets provided there would be no adverse impact on the reliable operation of the IMO controlled grid.
- Settle demand response for aggregated load in such a way as to maintain the settlement integrity of the market.
- Improve relationship between pre-dispatch and dispatch prices.
- Provide price signal.
- If funding for an economic demand response program is provided through uplift; IMO would administer settlement.
- Implement Market Rule changes as required.

3.3.5 LDC

- Comply with OEB requirements for metering and data provision.
- Act as an Aggregator for demand response loads (advisory group did not discuss in detail).

3.3.6 Aggregator:

- May need to become a wholesale market participant (advisory group did not discuss in detail).
- Bring retail loads to the wholesale market.
- Develop the demand response products and market them to Retail consumers.

Aggregators could include: individual retail customers, groups of retail customers, LDCs, industry associations, Retailers, energy services companies.

3.3.7 Customers

While not having a 'role' per se, other than to respond to prices and participate in the market, we felt a distinction between different customer types may be instructive:

- Wholesale Customers (market participants (MPs))

All Retail customers including:

- Retail non-designated with interval meters (pays HOEP according to their own load shape)
- Retail non-designated without interval meters (pays HOEP according to LDC Net System Load Shape)
- Retail designated with interval meters (currently pays fixed price; could in future opt out to be charged according to actual load shape, or custom Retailer price offers).
- Retail designated without interval meters. (currently pays fixed price; could in future be charged on seasonal and/or 'tiered' rate).

3.4 Meta Evaluation

In order to evaluate the efficacy of the framework model the following measures could be used:

- Review of program on a regular basis. While 3 or 4 years may be necessary to gauge the success of longer-term customer participation (e.g. residential aggregators), a review of participation by larger consumers could be done on a much shorter time frame, e.g. 1 year.

- An economic DR program should be results based. That is if an incentive is given to a load to put systems in place to reduce load and they can't demonstrate they have delivered then they should have to give the incentive back.
- Monitor level of participation (MW)
- Monitor range of sector representation in participation (wholesale and retail markets, industrial, commercial, residential and agriculture segments)
- IMO needs assessment
- To be reviewed when fixed price is removed

3.5 Needed Changes to Foundation

Fundamental changes include:

Providing the ability for Retail loads to participate in the Wholesale market. This is envisioned through the newly created license category of Aggregator. The Aggregator would have to meet certain IMO compliance obligations, but would not have the requirements for IMO compliant metering and facility registration as current wholesale market participants do.

Providing incentives under an economic demand response program for loads to develop capability to respond to market prices. The design of such a program would require careful assessment of specific barriers that are being targeted to overcome, practical administration, equity by encouraging participation amongst all customer sectors. In a well functioning market different customers would 'compete' by reducing demand in response to market prices according to their individual needs and thresholds. This is fully consistent with how the market allows for competition amongst generators to supply load.

For small consumers, the removal of fixed pricing at an artificially low level is a prerequisite to developing any demand response capability. The extent and form of price exposure can range from seasonal and 'tiered' or graduated rates, to simple time-of use block rates, to full spot market exposure. This can be the subject of continued debate and market testing.

If LDCs are to be load aggregators, s.71 of the *Ontario Energy Board Act, 1998*, may not be broad enough to facilitate.

3.6 Policy Considerations

This section provides an overview of two divergent views and a position generally supported by the Group.

Natural Demand Response

During the Advisory Group discussion of December 2, 2003, a variety of positions were advanced respecting potential policy reasons to promote demand response, including:

- Increasing consumer participation in the market
- Increasing the ability of consumers to respond to price signals
- Reducing overall prices and costs to consumers
- Avoiding uneconomic investments in generation, transmission or distribution

An economic approach to demand response would suggest that the purpose (and benefit) of a market for electricity is to provide efficient economic signals for suppliers and consumers, to appropriately allocate scarce societal resources and to efficiently allocate risk.

The apparent short-term inelasticity of demand during peak demand periods, and anecdotal evidence about industrial and commercial customers 'waiting on the sidelines', have been put forward to argue the need for an explicit program to reduce barriers to consumer participation in the market and to encourage reductions in demand where price signals alone would seem to be insufficient.

There are two possible dimensions to this policy problem.

The first possibility is that demand is elastic but that there are structural, informational or technical barriers that inhibit customers from responding appropriately to price signals. If the presence and magnitude of barriers is sufficient to suppress a demand response that would otherwise have taken place in response to price, thus resulting in an inefficient (and suboptimal) market outcome, then it might be appropriate to suggest a policy response that would overcome those barriers, by making structural changes to the market, providing information to consumers or by providing technical assistance to enable customers to respond appropriately to price signals.

The second possibility is that customers are not responding to price because (a) demand is elastic but the price levels are too low to induce a reduction in demand, or (b) demand is truly inelastic, in which case one would not expect a change in demand no matter the price. In both these cases, the lack of demand response is an efficient market outcome.

To promote a change in demand where that change is not supported by market forces would be to promote an inefficient market outcome, i.e., one that would make society worse off over all, even though some customers might realize private benefits through lower bills. If policy induces an inefficient (e.g., lower) level of demand by some customers than the market would suggest, this will have the effect of artificially reducing prices below the level at which the market would clear on its own. Artificially lower prices have the dual effect of increasing demand and reducing economic signals for investment in supply. Artificially lower prices also have the effect of increasing resource consumption, increasing environmental pollution and reducing incentives for conservation that would otherwise have been provided by a competitive market. Rather than avoiding *uneconomic* investment in supply, prices that are artificially low also have the detrimental effect of inhibiting *economic* investments in supply, leading to a sub-optimal level of supply, and reducing the adequacy and reliability of the electricity system.

If the policy intent is to reduce customer bills by making side payments to some customers to reduce demand during peak periods and thus to reduce prices during those periods, then it will be necessary to create a second policy to provide side payments to generators to correct the price signals and make up for the lost incentive for new supply.

Economic Demand Response

Paying customers to curtail their load on peak demand and/or supply shortfall days may provide the following benefits to Ontario:

1. Reduced market clearing price. Toward the limit of system capacity, small changes in demand can have dramatic effects on prices. The drop in market clearing price will lower consumers bills. The magnitude of the difference will depend on their consumption at that time (or the consumption of the customer class with which they are grouped in the net system load shape). In addition for many periods of tight supply, the uplift charges associated with importing power and the Import Offer Guarantee would also be avoided.

2. Reduced risk of emergency reliability measures including voltage reductions (brownouts), voluntary load shedding (emergency demand response programs) or involuntary curtailment (blackouts).

3. Reduced need for new generation and transmission infrastructure.

The *New England Demand Response Initiative* is proposing that the New England ISO pay customers $500 per Mwh (US$) or more to curtail their consumption during peak demand periods. [New England Demand Response Initiative, *Dimensions of Demand Response: Capturing Customer Based Resources in New England's Power System and Markets: Report and Recommendations of the New England Demand Response Initiative,* (July 23, 2003), p. 16]

A traditional argument against economic demand response programs has been that lower market clearing prices would reduce the incentive for investor-owned corporations to build new supply. However, if the Government of Ontario decides to enter into long-term contracts with investor-owned companies for new supply, a high spot price for electricity will no longer be necessary to induce new supply.

Therefore some members of the Advisory Group recommend that a key objective of the IMO's economic demand response program should be to reduce the electricity bills of consumers and the Government of Ontario by reducing the market clearing price for electricity and the need for high-price imports on days for which high prices are forecast.

Transitional Demand Response - A Reconciliation of Opposing Views

In markets such as the northeastern region of the United States where economic DR has been implemented the prospect of lower than competitive prices has not been the principal attraction. Rather, the case in favor of active DR programs recognizes the immature state of markets in the process of deregulation in which various impediments stand in the way of what has been called underlying or natural demand response. DR measures are viewed as a transitional mechanism to increase demand elasticity during the period that the market is transformed into this more mature state.

The impediments to demand elasticity may be technological, behavioral, policy-based, or just the time it takes to install meters and other required capital. In Ontario we have the added serious, policy-based impediment of fixed prices for about half of the market. These impediments distort the market away from the competitive outcome that would result if the market were functioning effectively. For example, if retail prices to a large segment of the market are fixed, then in periods of high demand prices will be higher than they would have been if the fixed-price policy had not contributed in a major way to the price inelasticity of demand and system reliability would be more compromised.

The purpose of active DR measures is to move the outcome back towards the competitive outcome. That is why the jurisdictions mentioned earlier have considered DR policies to be transitional and have implemented them with termination dates. When the market is mature and the impediments to natural demand response have been eliminated the economic DR programs are removed. In markets which have DR measures, the use of the transitional framework has satisfied both activists and those striving towards market-based solutions.

3.7 Issues

IMO Mandate to Achieve Efficient Prices

While the IMO would be involved in any demand response initiative that is integrated with and settled in the IMO-administered (wholesale) markets or is provided as a control measure used to ensure system reliability, having the IMO be responsible for all demand response initiatives could put the IMO in a conflict of interest position with respect to its role as impartial manager of the market system and in financial settlement between buyers and sellers. This is particularly true in the case of demand response initiatives where the objective is to reduce customer bills or reduce the price of energy. The IMO mandate is to achieve efficient prices in the electricity market and not the lowest prices than can be achieved through market intervention.

The inclusion of societal benefits in any analysis would be beyond any financial criteria currently used by the IMO.

Retail Metering

It was recognized that Retail Customer metering and meter data was, in most cases, central to the settlement of Aggregator loads in the IMO market. These Retail meters are presently the exclusive domain of the LDC's. Some members of the group expressed concern over the capability of LDC's to fulfill metering and data obligations, based on experience to date since market opening.

While some stakeholder to this Consultation proposed allowance for competitive meter services in the Retail market, as currently exists in the Wholesale market, the advisory group did not discuss this in detail.

Other stakeholders argued for retention of LDC responsibility for Retail metering, pointing out the many benefits that could accrue to the LDC with prudent application of 'smart' metering e.g. outage detection, theft of power.

In this framework we articulated the need for the OEB to prescribe more stringent requirements for LDC's to comply with customer requests for metering changes and provision of data.

Mass deployment of 'smart' meters vs. market penetration.

The Advisory Group heard presentations from a number of meter providers, with different perspectives on the most appropriate means of applying 'smart' metering to the broader market. Some general observations were that:

- There appears to be good competition for the provision of meter services.
- Despite varying cost estimates, technical innovation and cost reductions were already occurring and were expected to continue.
- Mass deployment of smart metering to customer groups that may not be price responsive was generally seen as wasteful and inefficient use of DSM/DR funds.

While this issue was not debated to any substantive conclusion, a penetration of smart metering into smaller customer classes would enable both DSM and DR, would facilitate cost reductions and technical innovation, and would provide the platform for new, innovative energy services.

Regulated Rates that provide a DR Effect

A fixed price is arbitrary and ensures that all people pay an average price even though few customers are 'average'. If there is to be an arbitrary price, it is better that there be several prices and that they reflect the HOEP accurately month by month, rather than a year at a time. Monthly prices reflect seasonal demand and minimize adjustments to cover revenue shortfalls or surpluses. Several prices or tiered prices would allow classes of users that used a large portion of off peak power to have a lower price. Farms, electronic manufacturing, ordinary households for example use more off peak power than most commercial and small industrial users. There could be an 'average' tier for most commercial and small industrial users. And there could be a summer peak premium to encourage conservation around the massive air conditioning peak. This summer premium might apply to homeowners who used over 1500 kwh in a summer month or to commercial class users who used more than 10,000 or 15,000 kwh in a summer month. This approach could also accommodate a fixed price for the first 750 kwh used each month to ensure that low income users are not harmed. The summer peak tier would provide a significant conservation incentive that a flat year round price or the same monthly price for all cannot provide. A winter premium would likely only penalize the poor who have no alternative heat and so is not suggested. This approach would encourage as much conservation as the market can undertake without subsidy incentives. Thus there would be less need for subsidy-based projects with objectives that can be achieved in the market. And this approach to ordinary consumer prices would have customers pay for the power they use according to whether they use more or less off peak power, so people would pay for what they use at something closer to its market value. Price signals would be more accurate without the need for billions of dollars worth of interval meters.

Custom Retailer Energy Rates.

It can be argued that the energy price offerings to residential and small volume consumers (prior to having energy prices fixed) were primitive compared to the choices they enjoy for other products and services, e.g. long distance and cell phone plans.

Wider scale adoption of interval meters to smaller customer classes would enable provision of more sophisticated and innovative pricing options to these consumers.

Large consumers already enjoy good competition and choice in the provision of different pricing offers from Retailers. There is no reason why smaller consumers could not enjoy the same benefits – the ability to buy 'blocks' of power to suit their needs – peak, off peak, summer, weekend, 1 year, 3 year.

An ideal end state is that such customized 'financial' energy products are readily available from competitive Retailers and sought out by informed consumers. This would greatly enhance market liquidity and would directly encourage demand response, benefiting all consumers.

LDCs competing with private sector in delivery of DR.

Providing regulated monopolies (i.e., LDCs) with DR and load aggregation service obligations may erect barriers to competition in the retail market.

3.8 Pros And Cons

Pros of DR Framework

Effectiveness
+ Recognizes that DR requires initial financial incentives for enabling response by loads into the market and for reducing and eliminating barriers in general.
+ Requires active and supportive action by LDCs in facilitating DR, where presently there is no incentive or reason for their participation.

Competition
+ Promotes the use of the private sector in securing DR load, either directly or as an aggregator.

Regulatory burden
+ IMO role as DR facilitator and integrator is consistent with their role as a market operator.

Cons of DR Framework

Accountability
- May require additional regulation to define "aggregators". Although identified as a con, there may be no other alternative.

Competition
- LDCs acting as aggregators is anti competitive, lacks transparency, and may be deemed generally unfair to private sector aggregators given the LDC role and definition as a "wires only" business. Better would be the process of LDCs facilitating access by aggregators to loads and load information.

4 CENTRAL AGENCY FRAMEWORK - Alternative Models

The following is a description of a “Central Agency” approach to facilitating Demand Side (DSM) Management and Demand Response (DR) initiatives in Ontario. This approach is in contrast to an OEB/Wires model in which the OEB provides regulatory oversight, but that the primary responsibility for pursuing DSM is left to the local distribution companies (LDCs) in the Province (see Section 5).

The Advisory Group considered three options in the context of a centralized approach. The first option, the Central Agency Model, would entail a new agency wholly responsible for all aspects of DSM. The second option would entail two major steps, the creation of a centralized agency and the creation of an energy efficiency utility (EEU). The agency would provide oversight while the EEU would be responsible for the design and delivery of DSM programs and initiatives. With the third option a centralized agency would be created, but all DSM activities would be carried out by third parties. The underlying premise of this third approach is that, to the extent possible DSM would be carried out on a competitive basis.

There are a number of common elements associated with the three approaches. The common elements are:

- All models assume that the funding associated with the agency would come from the energy sector. A system benefit charge (SBC) would be developed and collected through rates from all end-use customers. It is assumed under these models that the Government would initially establish the overall amount to be collected and the specific details around the collection mechanism. After some initial period it may be up to the agency to develop its own budget and business plan. That may require changes to the SBC. All models also assume that there may be a role for the OEB to approve the agency’s annual budget in the same way it oversees the IMO and its fees.

- All models assume some level of Government oversight. Specifically, the intent is for the Government to initially set high level objectives for the agency and set that out through legislation. There would be a requirement for the agency to submit an annual report to the Minister.

- All models assume that there would be a sunset provision for the agency. In effect, the agency would not continue necessarily into perpetuity. After an initial term, the Government would be required to make a decision as to whether or not the agency would be dismantled or would continue with its mandate.

- All models assume there would be mechanisms for stakeholder input both on a formal basis and on an ad hoc basis.

- In all models the Government and the agency may be challenged to balance the collection of DSM/DR funds (i.e., the SBC), the allocation of those funds, and the pursuit of TRC benefits. There may have to be trade-offs between equity and societal benefits.

- In all models the principles and the terms of reference for the audit of DSM program results should be established and standardized to the greatest extent possible at the beginning of the process, i.e. before program delivery begins, to avoid after-the-fact dispute over the auditor's role and findings, and to ensure a timely and streamlined audit process. Stakeholder input should be considered in the establishment of the audit principles and terms of reference.

4.1 Overview

4.1.1 Central Agency Model

This option would entail the creation of an independent, non-profit, self-funding agency3 with the mandate of promoting and facilitating demand side management and demand response initiatives in Ontario. The agency would be created by legislation and report to the Minister of Energy. The legislation would set out the broad objectives and mandate of the agency. The agency would then carry out those objectives as an independent entity.

The model envisioned could be set up in a way that mirrors the new OEB model. This would ensure an added level of independence relative to having the responsibilities carried out as a government department. It would not be subject to all of the government restrictions regarding hiring, compensation and contracting out. Individuals within the organization could be provided incentives to perform through creative salary and bonus schemes.

The mandate for the agency would be set by the Minister and embodied in the legislation. In terms of accountability there would be a sunset clause that would necessitate a conscious decision at the end of the term (3-5 years) either to continue with the agency, dismantle it, or undertake some reform.

The agency would be responsible for all aspects of DSM and DR. It would have the ability of doing activities in-house or contracting out. To the extent there was a need to develop incentive mechanisms to facilitate cost-effective DSM the agency would develop those mechanisms and the framework within which to provide those incentives.

The Minister/Government would initially set the budget for the agency. It is assumed that the money to fund the organization would come from the energy sector likely through a system benefit charge. It would not be funded through general revenue. The initial budget would drive the creation of the initial business plan.

3 E.g. a crown corporation like the Workers' Compensation Board.

The agency would develop ways to facilitate stakeholder input into its activities. One structural option to facilitate such input would be have the agency Board of Directors comprised of both independent and stakeholder representatives.

4.1.2 Central Agency Plus EEU Model

This model is similar to the central model described above, but would entail the creation of another entity, an Energy Efficiency Utility (EEU)[4], to design, develop and deliver DSM initiatives.

This model is based, in large part, on the system currently operating within the State of Vermont (the Vermont Model).

The agency would develop an RFP and establish selection criteria for the new entity. The EEU would be selected through a competitive bidding process. The agency would also establish incentives for EEU attainment of specific goals, both short term and longer term.

The evaluation of bids for potential EEUs will not be based solely on criteria such as the overall budget, dollars per kwh or TRC benefits. The central agency will instead define a range of criteria that will be used in the selection of the best overall bid. No single factor will be determinative. Through the establishment of the criteria the central agency will be able to address broad social policy issues.

The EEU could be either a "for profit" or a "not-for-profit" entity.

A variant on this model is for the "central agency" to be the OEB.

4.1.3 Central Agency – Competitive Model

This model is also a variant on the first central agency model. An independent, non-profit, self-funding agency[5] would be created though legislation as set out above. Transparent governance structures could include stakeholder representation on the Board of Directors or through a stakeholder advisory group.

The agency would be funded through the energy sector through a system benefit charge. The levy on customer bills could vary by customer class. It is also possible under this model to have funding provided by applicants or private sponsors.

4 E.g. as in Energy Efficiency Vermont on contract to the Vermont Public Service Board or, to a lesser extent, Agricorp which is a business arm of the Ministry of Agriculture and Food.
5 E.g. the National Research Council with sub-group panels for different areas of research.

The agency would set objectives and priorities and allocate funding among "Targeted Program Funding Pools." The individual program pools would be targeted at specific DSM and DR opportunities, customer classes or market segments.

Each of the pools would have separate "Project Review Panels" appointed to provide oversight and peer review of program or project proposals (e.g. stakeholder representatives, academics, industry experts etc.)

The difference between this model and the centralized model described above (in section 4.1.1) is that the agency itself would promote its mandate, carry out marketing and monitoring functions, but would not act as an executor of DSM programs. All of the work with respect to DSM would be carried out by third parties. The underlying principle encompassed by this model is that to the greatest extent possible DSM should be designed, developed and delivered within a competitive framework.

The Board of Directors would determine where to focus funding and how to shift funds between pools with a view to maximizing long-tem benefits and involving all parts of society. The Project Review Panels would solicit and select applications to carry out initiatives from within the private sector.

The agency could also target funding to reduce market barriers and develop necessary infrastructure to enable wholesale or retail demand response activities.

Projects would be selected based on: competence of the applicant, clarity of the plan, anticipated value of the DSM/DR benefits, long-term conservation benefits, positive externalities and overall cost.

4.2 Roles And Responsibilities

4.2.1 Setting High Level Objectives/Mandate of the Agency

4.2.1.1 Central Agency Model

The Minister/Government would initially establish and set the high level objectives (e.g. promoting energy efficiency, conservation, protection of the environment, enhancing the reliability of Ontario's electricity system, etc.) and embody those in the statute.

4.2.1.2 Central Agency Plus EEU Model

The Government would initially establish and set the high level objectives either through legislation or by ministerial directive to the OEB. The Government would also set the initial budget. After the initial period new budgets for the agency would either require approval by the OEB or would be set by the OEB.

4.2.1.3 Central Agency – Competitive Model

Under this model, as under the other centralized approaches, the Government would establish the legislative framework for the agency and would establish an initial system benefit charge.

4.2.2 Setting and Identifying Objectives

4.2.2.1 Central Agency Model

Having been given its mandate by the Government the agency would then set more detailed objectives and establish a business plan. It is assumed that there would be mechanisms put in place that would allow for stakeholder input both in terms of the objective setting and the establishment of priorities.

In terms of establishing a business plan this would be an iterative process. The agency would need to determine where to get the best results, what sectors to target and what types of activities would best suit those sectors. Having been given a limited budget the agency would then need to determine how best to get results given those budget restrictions. This would require prioritization.

Some examples of trade-offs might include whether or not to focus on short-term priorities (peak shifting) or longer-term priorities (market transformation) or to what extent both need to be pursued. It would also need to determine whether or not it should focus some efforts on all sectors (e.g. residential, commercial, industrial, agricultural, MUSH) or focus on the sectors where there is more potential in terms of achieving energy efficiency and conservation objectives.

Challenges in terms of setting priorities may be how to deal with the remote communities in Ontario and whether to target programs to low-income consumers.

The objective setting and prioritization would be informed by internal research and stakeholder input.

4.2.2.2 Central Agency Plus EEU Model

Under this model the independent agency would set goals and criteria (e.g. transparency, stakeholder involvement, universality, sectors to target)

The agency would also establish incentives for the EEU. This may include the establishment of financial incentives for meeting specific goals and/or targets. The agency may also establish penalty schemes for failure to meet established goals and targets. These goals and targets would be both short-term and long-term and could address:

- TRC savings

- Distributional requirements (percentage of programs the avoid lost opportunities or percentage of programs that target low-income customers
- Market transformation objectives

The selected EEU would be required to develop a business plan that provides both budget allocation and program details.

4.2.2.3 Central Agency - Competitive Model

The agency would set objectives and priorities and would allocate funding, based on those priorities to each of the Targeted Program Funding Pools. The pools would be established by the agency. The funding pool targets might include customer segments or specific system interests. For example:

- Customer Segments
  - Industrial and Agricultural
  - Commercial and MUSH
  - Residential and Small Commercial
  - Rural and Remote
  - First Nations
  - Low Income Residential
- Specific System Interests
  - Demand Response
  - Research and Development
  - Transmission/Distribution Network (line loss capture)

Programs could have mandated objectives that serve the needs of the targeted purpose.

4.2.3 Identify and Screen Opportunities

4.2.3.1 Central Agency Model

This role would be carried out by the agency. Assuming that the agency had an infrastructure responsible for research, data collection etc. it would identify opportunities and screen them for cost-effectiveness.

4.2.3.2 Central Agency Plus EEU Model

The EEU would identify and screen opportunities and might conduct research. Research would likely be a special case of expenditure for the EEU if it is better suited than the central agency to conduct research.

All research conducted by an EEU, including results and underlying data would be unconditionally provided to the central agency. There will be no limitation on the central agency's use of that research.

4.2.3.3 Central Agency – Competitive Model

Under this model the Project Review Panels would be responsible for screening opportunities presented and identified by bidders. The agency would establish the screening criteria and standards. Cost-effectiveness is the primary objective.

4.2.4 Design and Develop Activities

4.2.4.1 Central Agency Model

The primary responsibility for designing and developing activities would be with the agency. Nothing would preclude the agency from contracting some of these activities out. For example, it could issue an RFP seeking someone to develop a range of agricultural programs.

With respect to some activities it might be more efficient for the agency to design and develop programs in-house. An example might be an informational program directed at all residential end-users in the Province.

The methods for screening programs and program measures would be developed within the agency.

4.2.4.2 Central Agency Plus EEU Model

The EEU would operate the same as outlined above. The EEU is primarily responsible for the design and development of its programs. The EEU would be permitted to contract out the design and development of all or part of its programs.

4.2.4.3 Central Agency – Competitive Model

The central agency would establish criteria for each of the Panels. The Panels would design and develop the criteria to be used in "calls for submissions", based on the overall agency guidelines. They would send out the tenders and select the contractors who would be responsible for program design and development.

A means of assessing both the methods for screening programs and the program measures proposed by successful contractors would need to be developed by the agency.

4.2.5 Deliver Activities

4.2.5.1 Central Agency Model

Under this model the delivery of programs would not be restricted to the agency itself. If it makes sense for the agency to deliver a program it can. However, it many cases it is recognized that other parties would be better suited. The range of parties would include customers, energy service providers, retailers, wholesalers, and distributors.

There would be a mix of delivery agents, depending upon the cost-effectiveness of different delivery options. To the extent there was a need to develop incentive mechanisms to facilitate cost-effective DSM the agency would develop those mechanisms and the framework within which to provide those incentives.

4.2.5.2 Central Agency Plus EEU Model

The EEU is primarily responsible for the delivery of programs. However, it could contract out part or all of the delivery activities to other delivery agents. This assumes there would be a mix of delivery agents. The ultimate mix of delivery agents would depend upon the cost-effectiveness of the delivery options.

4.2.5.3 Central Agency – Competitive Model

The delivery of all DSM programs would be carried out by third parties. The parties eligible for undertaking the programs would include LDCs, aggregators and retailers, customers and HVAC contractors etc.

Demand response enabling activities could be provided by successful project proponents. Demand response market activities could potentially be undertaken by:

- IMO registered consumers bidding their power back into the market,
- LDCs bidding back controlled power use, such as for water heaters, back to the market, or
- an aggregator competitively retained by the agency to aggregate and bid back power from other customers.

The agency might retain a load aggregator for the purpose of bidding retail demand response in IMO-administered markets. The process to achieve this may be similar to that employed to secure contract services for DSM/DR delivery.

4.2.6 Monitoring and Evaluation

4.2.6.1 Central Agency Model

It is assumed under this model that the agency would have an internal group responsible for monitoring and evaluating the initiatives. Although the primary responsibility of this function would rest with the agency, there would be nothing precluding it from contracting these functions out.

The agency would determine the process and methodologies for monitoring and evaluation. To the extent programs screened and evaluated on the basis of the total resource cost test, all inputs into the TRC would be determined by the agency and updated periodically. Stakeholder input would be sought in the initial development of the monitoring and evaluation process.

4.2.6.2 Central Agency Plus EEU Model

Under this model the EEU is primarily responsible for monitoring and evaluation of programs. The monitoring and evaluation protocol should be developed at the beginning of the programs in consultation with stakeholders.

4.2.6.3 Central Agency – Competitive Model

Under this model the central agency would oversee measurement, audit and verification of DSM/RD initiatives. Setting project and monitoring and verification specifications would require technical expertise, some of which would be provided by the agency and much of which would be contracted out.

4.2.7 Audit

In all sub-options of the Central Agency model, the principles and the terms of reference for the audit of DSM program results should be established and standardized to the greatest extent possible at the beginning of the process, i.e. before program delivery begins, to avoid after-the-fact dispute over the auditor's role and findings, and to ensure a timely and streamlined audit process. Stakeholder input should be considered in the establishment of the audit principles and terms of reference.

4.2.7.1 Central Agency Model

Like the M & E function the agency would be responsible for auditing program results. It would be preferable for the agency to contract out the audit function.

4.2.7.2 Central Agency Plus EEU Model

Under this model the central agency will manage the audit process that will be completed by an external independent auditor. The selection of the auditor as well as the principles and guidelines will be determined by the central agency. The audit principles will be developed by the agency in consultation with stakeholders.

In terms of the measurement of costs and benefits overall performance measures will include joules saved, dollars spent/saved, losses reduced etc. The total resource cost test (TRC) will be used to measure results of DSM. The EEU will define input parameters for screening (such as avoided cost or discount rates) and carries out the screening process.

4.2.7.3 Central Agency – Competitive Model

The central agency would have primary responsibility for auditing and evaluating all Panel funded initiatives. The agency would employ external auditors to verify that the work was done and that the contracted energy savings occurred.

In addition, third party auditors would evaluate the Panels' performance as well as the performance of the market players delivering programs. The auditors would report to the central agency.

4.3 Meta Evaluation

4.3.1 Central Agency Model

Accountability of the agency could be carried out in a number of ways. As noted above the establishment of a sunset clause in the legislation would ensure that the agency was dismantled if it outlived its use. An explicit government decision would be required for it to continue to operate and pursue its mandate at the end of an initial term.

The agency would be required to submit an annual report to the Government describing and justifying its activities and expenditures.

The intent with this model is to develop mechanisms to facilitate stakeholder input. There could be a statutory stakeholder advisory group that provided input on an ongoing basis. There could also be mechanisms whereby stakeholders are asked at a specific point in time to provide input on priorities, programs, and evaluation techniques. There could also be a set of stakeholder committees supporting/advising on many agency functions.

4.3.2 Central Agency Plus EEU Model

Under this model there would be a sunset date for the agency, requiring a decision to either renew the mandate or to choose another approach.

There would be performance standards developed for the agency itself. With respect to the EEU its performance would be evaluated at the end of its contractual term.

4.3.3 Central Agency - Competitive Model

The agency would receive ongoing stakeholder input either through the Board of Directors or a stakeholder advisory group. Stakeholders can also submit proposals to panels and many will likely act on panels.

The agency would be required to issue public reports on an on-going basis and an annual report to the Minister of Energy.

4.4 Needed Changes to Foundation

4.4.1 Central Agency Model

The centralized agency would be established through new legislation.

Further, the agency would require access to aggregate customer information to carry out its market research and market planning activities. Changes may be required to the Electronic Business Transaction (EBT) system, the OEB's Retail Settlement Code (RSC), or privacy legislation to accommodate this.

4.4.2 Central Agency Plus EEU Model

The centralized agency would be established through new legislation.

Further, the agency would require access to aggregate customer information to carry out its market research and market planning activities. Changes may be required to EBT, RSC, or privacy legislation to accommodate this.

4.4.3 Central Agency – Competitive Model

The centralized agency would be established through new legislation. There may also be a need to change some laws to allow for enhanced access to information so monitoring and verification could be undertaken.

4.5 Demand Response and Load Aggregation

The overall responsibility for demand response and aggregation could rest with the central agency. This sub-group did not consider how, specifically, that would be done.

4.6 Pros and Cons

Pros of All Central Agency Models

Effectiveness

+ Reaches across LDC boundaries much more effectively than LDC model.
+ Avoids the need for the private sector to coordinate its sales and delivery with multiple organizations across the province.
+ Helps facilitate chain account needs with respect to DSM/DR. These can be more easily addressed by working with one agency as opposed to several.
+ Probably better tracking and quantification of program results than under the LDC model.
+ There would be no need to have an LRAM mechanism

Universality/Consistency

+ Since the central agency is responsible and accountable for all monitoring and evaluation, there is a higher likelihood of consistent application of M&E methodology and parameters to all programs at all levels. This is ensured by the fact that there would be an internal M&E department which would either do M&E itself and thereby control the M&E process, or in developing the criteria for selecting an outside company to perform this function.
+ Provides for a consistent set of program rules across the province.

+ Provides the private sector with a central point of contact on DSM/DR policy, planning and programs.

Competition

+ With consistent and uniform program rules, the private sector will be better able to secure participants on a broad, cross provincial basis, consistent with their existing services delivery channels.
+ It has been noted as a Con that the agency would not have established relationships with customers, stakeholders and allies. However, the private sector would be eager to establish a close working relationship with the agency and would encourage this approach of engagement at the earliest stages of the agency's establishment.

Regulatory burden

+ Relative to the LDC/OEB model, doesn't depend on complex and costly regulatory mechanisms to mitigate utility risk and revenue erosion.

Cons of All Central Agency Models

Effectiveness

- If a centralized DSM agency is created to promote energy conservation, and no changes are made to the OEB's regulatory framework for wires companies, the DSM agency's objective will be contrary to the financial self-interest of the wires companies (i.e., maximize its customers' electricity consumption). This could frustrate the achievement of the Government's energy conservation and efficiency goals.
- Absent an LRAM for the wires companies it is doubtful that these entities will play a supportive role as incremental DSM that they foster will erode their revenues in the current rate period and erode their growth in the long run.
- In the opinion of some Advisory Group members, the track records of Ontario Hydro and OPG raise questions about the efficacy of a centralized DSM agency. Specifically, some members believe that the DSM programs developed and /or implemented by a single, non-profit, centralized DSM agency are unlikely to be as innovative, aggressive, cost-effective and customer-focused as those which would be developed and implemented by multiple, decentralized, profit-driven wires companies.

Accountability

- The funding in rates coupled with high level regulatory oversight of the central agency by the OEB should be a mandatory component of these models, not an option. It is not appropriate for tax revenues to be used to fund DSM which is intended to ameliorate the failings of the energy sector – users of energy should pay in proportion to use. It is most appropriate that the energy users paying for the programs have a public forum in which the level and general direction of the effort is evaluated from time to time. Even in the absence of ratepayer funding, the complexity of DSM suggests that sophisticated ongoing regulation is appropriate and has the benefit of shielding the program from undue political interference.

Targeting

- A central DSM agency would be required to establish uniform, province-wide DSM programs. This approach may be appropriate in a small, homogeneous state such as Vermont. However, a cookie-cutter approach to DSM is neither customer-focused, nor cost-effective in a province as large and diverse as Ontario. For example, there is a dramatic variation in customer needs and demographics from Atikokan to Sarnia to Toronto to Gananoque.

Competition

- The Agency could compete directly with the private sector for design, development and implementation of DSM/DR programs. A mechanism to restrict the Agency's activities should be built into its operating charter. Contracting out to accomplish the agency's tasks, as opposed to conducting activities in-house, should be strongly encouraged under this model. One way to ensure that contracting out is the primary method of conducting activities would be to limit the size of the agency or its internal administration budget. This would force it to secure expertise and delivery from the private sector, while using its own personnel for planning and project management.

Delay

- The creation of a new centralized DSM agency will delay the implementation of DSM programs relative to the wires model.
- Larger organizations tend to be more bureaucratic and could result in slower than optimal start-up and implementation. It is proposed that the Agency's size be limited to encourage efficient decision making and engagement with private sector delivery agents.

Pros of Central Agency Does All Framework

Effectiveness

+ There would be economies of scale achieved in having one entity responsible for the design and delivery of DSM.
+ There would be more of an opportunity to influence the overall market rather than pockets of the market due to the scope and scale of provincial programs.
+ A centralized agency would have the advantage of being in a better position to compile and store useful provincial data in terms of usage, customer behavior, technology and market potential. It would also have better corporate memory and the ability to retain intellectual property in a centralized place.

Universality/Consistency

+ A centralized agency would allow for the development and delivery of consistent programs across the Province.

Accountability

+ Stakeholder input from organized provincial stakeholders could be better facilitated. Rather than attempting to influence decisions at an individual LDC level it would be more efficient to provide input to one central agency.
+ If the centralized model was applied to both gas and electricity there would be better attention to market mix and the assurance that fuel switching is not counted as DSM
+ As an independent agency there are advantages relative to a government department in that there would be less political meddling. There would be a day-to-day independence from government.

Public policy

+ A centralized agency would be better able to partner and coordinate initiatives with other governments. Efforts could be better leveraged. (Kyoto, NRCan)
+ A central agency would be in a better position to promote social and environmental benefits.
+ There would be greater potential to affect market transformation through a centralized approach.
+ A central agency would be more inclined to undertake structural efforts in terms of education, market transformation, and research and development.

Regulatory burden

+ The model would result in greater regulatory simplicity relative to the LDC model where up to 93 LDCs would have to seek approval for a DSM budget, an SSM, an LRAM and a DSMVA.

Cons of Central Agency Does All Framework

Public policy
- A centralized body may dilute DSM/DR objectives with other criteria
- A government agency may be susceptible to longer term political meddling.

Accountability
- There would be the potential for bureaucratic inefficiency.
- There would be the potential for empire building.
- Under this model it would be difficult to adequately forecast and measure individual DSM impacts.

Effectiveness
- There would be a lack of access to proprietary information. (i.e. Billing information on customers)
- A centralized approach may limit the availability of mechanisms used to incent results.
- Lack of performance-based incentives may not result in the most cost-effective program delivery.
- There may be the potential for passive and/or active LDC opposition under this model as they are not compensated for lost revenue.

Targeting
- The existence of one large centralized agency would not allow for input and effective participation from smaller, remote, locally focused stakeholders.
- There is a risk that a centralized agency would be less sensitive to local needs and geographic diversity.

Competition
- There is a drawback in that the agency would not have established relationships with customers, stakeholders, and allies.

Pros of Central Model - EEU Framework

Effectiveness

+ Increased competition among potential EEUs will lead to more cost-effective program development and delivery.
+ The EEU should be more business like in its approach to implementing its mandate than one central government agency. The EEU would be more business like due to the fact that their profitability would be directly related to its ability to manage costs and achieve measurable results in a timely manner.
+ The potential business opportunities for EEUs will promote greater development of, or recruitment of talent and expertise.
+ Having an EEU will allow for a broader range of incentive schemes.

Universality/Consistency

+ Helps facilitate chain account needs with respect to DSM/DR. These can be more easily addressed by working with one agency as opposed to several.

Accountability

+ There would be increased accountability by engaging a separate entity to design and deliver the programs on a fixed contractual basis.
+ The establishment of the centralized agency and an EEU will lead to greater transparency relative to the other two central agency models.
+ A separate entity, the EEU, will be subject to greater business discipline relative to a government agency.
+ The short-term contracts act as a discipline against empire building and bureaucratic inefficiency.

Cons of Central Model - EEU Framework

Effectiveness

- The short-term EEU contracts may act as a disincentive to longer-term initiatives like market transformation, research and development and education.
- There could be a potential for private gain at the expense of public benefit. (The solution would be to have the RFP/call for submissions well-defined to avoid this outcome)
- Creating a separate single EEU contract for development and delivery apart from the central agency creates an unnecessary level of complexity and bureaucracy.
- Under this model the number of layers could make it more difficult to get things done. More layers of authority could be cumbersome.
- There may be some reduced flexibility with this option in terms of making mid-stream corrections to program design. Contractual provisions may

make it difficult.

- Short-term EEU contracts may limit the scope and creativity of program design and implementation possibilities. As examples, the following areas all require multi-year approaches for results to be delivered: Changes to codes and standards; improvements in new building design; and implementation of large projects in the large ICI markets.
- Incentives for EEU performance adds an additional and unnecessary cost to overall program delivery. Incentives should be focused on reducing financial barriers to implementation at the end-user level, not at the agency/EEU level.

Accountability

- The Agency should define input parameters for screening, otherwise the EEU could be conflicted in the setting and carrying out of both screening parameters and screening itself.

Regulatory Burden

- This option would necessitate the creation of two new entities rather that using the existing OEB infrastructure.
- Increased risk that the central agency may interfere with the EEU's plans and implementation if disagreements occur, creating confusion with end-users and allies (the private sector) on policy, direction and implementation.

Competition

- With the exception of the initial RFP for EEU, subsequent RFPs for EEU would not be competitive. The incumbent EEU would have significant advantages over its competitors, including: access to planning and program results, internal consultations, having built and developed significant expertise from carrying out its responsibilities as EEU.
- There would be a risk under this model that the first successful EEU would become the permanent EEU. In the second round others may find themselves at a disadvantage.
- The EEU may not have the requisite incentives of engaging the private sector in the design, development and implementation of programs, where the experience of delivering results currently exists.

Delay

- Designing a good RFP/call for submissions and contract parameters may be a challenge.

Pros of Central Model - Competitive Framework

Effectiveness
+ Private sector engagement helps ensure aggressive implementation and results given that they are motivated on a business case basis to deliver services and do so in a competitive manner.
+ Capacity for the central agency to take exceptional projects or programs and roll them out on a larger scale.
+ Suits a variety of projects without institutional bias to any one.
+ Less bureaucratic than other models. More of the SBC is likely to go to actual programs.

Universality/Consistency
+ Helps facilitate chain account needs with respect to DSM/DR. These can be more easily addressed by working with one agency as opposed to several.

Competition
+ Actively seeks to engage the private sector, where implementation experience and motivation for constant innovation and improvement currently exists, into the process of development and delivery of results.
+ Since the private sector cannot pass costs to ratepayers, this model transfers risk from ratepayers to the competitive delivery participants.

Cons of Central Model - Competitive Framework

Effectiveness
- Probable lack of universal access to programs; reduced possibility that a particular DSM/DR program would be available to customers throughout the province; further, communication of available programs may also be lower than other options; this is a particular concern for customers that have energy services needs that cross franchise/distributor boundaries. This drawback occurs in Option D also.
- This approach may encourage cream skimming and lost opportunities. It would encourage entrepreneurs to find the least expensive efficiency – i.e. to go after the low hanging fruit first. For example, if delivery entities go into a residence and do the cheap and easy showerhead replacement but don't get the more difficult and expensive (but still cost-effective) hot water pipe wrap, it may not be cost-effective to return a second time due to the transaction costs. Similarly, if an entity intervenes in the commercial new construction sector to improve lighting efficiency but doesn't go farther to get the added benefit of better windows which in combination would allow downsizing of the cooling system we may lose the window and HVAC opportunities for 15-30 years (until the windows and HVAC system are being simultaneously replaced).
- Economy of scope for market transformation may be lost. Many programs only work well on a provincial scale (influencing manufacturers to upgrade

appliances). With (a limited number of) LDCs or a conservation utility it's possible to imagine a provincially coordinated approach that utilizes the research and skills of the same portfolio managers. (See for example the Northwest Energy Efficiency Alliance which is a non-profit alliance of several utilities that receive SBC funds and that coordinates and conducts regional market transformation activities.) Not so with an auction approach (where there is no research and management expertise assembled). We would still require a Market Transformation effort. It's hard to imagine an auction for market transformation programs which are often negotiation efforts rather than pre-packaged proposals capable of being bid, and which would, by virtue of being province-wide, be too risky for most entrepreneurs to take on.
- The competitive approach could lead to inconsistent and overlapping program delivery. How does the auction deal with entrepreneur A doing a meter-driven whole house energy use reduction program and entrepreneur B claiming savings for a smart light bulb program that has overlapping participants with entrepreneur A's program? Does each auditor have to check every other program's participant roster? With a portfolio management approach, the market can be segmented at the outset to avoid overlapping participants
- Customer service could be compromised. Given that a lack of time and information to evaluate energy efficiency options is one of the market barriers (hassle or customer transaction cost) numerous competing private efficiency offers won't help consumers determine what is optimal for them. Choice is nice but consumers do place value on having trusted experts pick winners. A regulated portfolio manager (LDC, Central Agency or EEU) would be accountable for their choice of measure.
- There would be a limited ability under this model to facilitate universal programs across the Province.

Accountability
- Complexity of Verification, Evaluation and Free Rider estimation may lead to verification being compromised. Savings (to be rewarded) must be verified and net of free riders -- we need good evaluation and audit of results. If there are too many players or approaches this will be unmanageable and at the very least we will lose economies of scale. Free rider estimates often require consideration of the program design (to account for participant selection bias). With too many program approaches this could be a daunting task.
- Fairness of cost allocation. In the absence of a utility role it may be more difficult to ensure that the benefits and costs are allocated fairly among different customer groups in different regions.
- Greater contracting means that more information is proprietary to contractor.

Regulatory Burden
- The creation of "Project Review Panels" appears too bureaucratic and limiting. It would be better if these panels existed within a central agency's role, staffed by agency staff, with the mandate to contract out development

and implementation, and engage stakeholder input as deemed necessary. This would provide the same intended benefit, while focusing on achieving results in a timely manner.

- Broad objectives issued by the panel under RFPs may solicit options from suppliers that are difficult to compare and evaluate. It may also create an unnecessary burden on the private sector that will be required to "sell" an approach twice (with the end-use client and then with the panel, with little certainty of success at either step). It would be better if project opportunities were developed in response to clear performance requirements allowing the private sector to pre-screen and self select. Private sector advancements in technology may enable more aggressive target results over time, there should be a mechanism for the central agency to take this into account. Rather than (or in addition to) using the RFP approach, the agency should have an open process for the private sector to present innovative solutions.

Targeting

- Comprehensive coverage is not assured. Geographic or socio-economic groups might not get equal access to programs unless there is a regulated accountable portfolio management function.
- Programs and resulting projects should be based on a clear business plan set by the central agency, and not left entirely to applicants who may be influenced by special interests.
- Difficult to target specific program/policy areas if no bidders.

Competition

- The agency should not directly act as a load aggregator. This is inconsistent with the competitive approach of this model. The agency should on the other hand encourage load aggregators through its programs.

5 ONTARIO ENERGY BOARD/WIRES COMPANIES DSM FRAMEWORK

5.1 Overview

In this model, Ontario's electric distribution and transmission utilities ("wires companies") are accountable to the OEB for ensuring that cost-effective energy conservation and efficiency programs are delivered to the end-use customers they serve.

The DSM budget would be based on a uniform baseline charge per kWh collected from all end users (e.g. 0.3 cents per kwh would provide an annual province-wide DSM budget of approximately $450 million assuming Ontario's total electricity consumption is approximately 150,000 Gwh). The budget would not be based on energy savings targets. A simplified incentive (e.g. SSM at 2% of TRC) would be available to all wires companies for their DSM.

The OEB would be responsible for the audit function for all wires companies to ensure a uniform, standardized approach that also minimizes the regulatory burden for the smaller wires companies. The OEB would retain, fund and manage an external DSM auditor and appoint and fund a small multi-stakeholder audit advisory committee. For large DSM portfolios an annual audit would be required. For smaller portfolios, audits that cover a multi-year period would occur at least every three years. Annual audits would be required for smaller wires companies if either the incentive, budget or LRAM exceeds predetermined financial thresholds.

Wires companies would be free to contract out the task of DSM portfolio development and management. Because the incentive mechanism proposed does not require the setting of a target the DSM regulatory process is simplified and DSM programs need not be approved in advance by the OEB. Accounts are cleared based on audit results and the audit rules are also simplified because there is no issue with respect to the treatment of changing assumptions. For situations where a utility chooses not to develop and manage DSM or contract out for management of its DSM portfolio, Hydro One should be designated as the default delivery agency accountable to the OEB for the utility's customers. Alternatively, Hydro One could become the default supplier only if a utility was unable to take on the DSM function or carry it out effectively. Another possible alternative could be that only smaller wires companies (based on a threshold set by the OEB) would be eligible to opt out of DSM, using Hydro One as the default supplier. A final alternative would require all wires companies to deliver or contract out their DSM programs.

It is anticipated that the number of entities delivering DSM will be reduced as most utilities will contract out or consolidate DSM portfolio management efforts to achieve economies of scale and thereby enhance the SSM reward. While Hydro One is designated as a default provider of DSM should an LDC decline to deliver or contract out the DSM obligation, the absence of an LRAM or an SSM for the LDC in that scenario significantly reduces the likelihood that it would occur as it would lead to revenue and profit erosion for the LDC.

Mechanisms to encourage joint delivery of market transformation programs and avoid inconsistent or redundant market transformation programs are proposed. Incentives for multi-year market transformation initiatives can be sought as required as part of the rate setting process or through an administrative process at the OEB.

LRAM and DSMVA are cleared on the basis of the auditor's findings. Initial budget/kWh, reward level, audit and account clearance rules and avoided costs are set by the OEB in consultation with interested parties.

Primary responsibility for DR is placed with the IMO. Aggregation of retail response by aggregators or wires companies is enabled.

5.2 Roles & Responsibilities

5.2.1 Determine DSM framework (was identify & set objectives)

The OEB would be responsible for identifying and setting the objectives for the overall DSM framework. Specifically, the OEB would be responsible for:

- setting the DSM budget, through approval of a uniform per kwh DSM charge (see section 5.2.1.2)
- setting guidelines for portfolio management (see section 5.2.2)
- determining the avoided costs to be used for evaluation and auditing of DSM programs (see section 5.2.1.6)
- hiring an independent auditor to perform annual audits (see section 5.2.6)

The objective of DSM under this model is to:

- reduce energy services costs;
- increase reliability of Ontario's electricity system;
- improve competitiveness of Ontario's economy; and
- enhance public health and the protection of the environment.

5.2.1.1 Accountability for DSM programs

Under this model, Ontario's electric distribution and transmission utilities ("wires companies") would be accountable to the OEB for ensuring that cost-effective DSM programs are delivered to the end-use customers they serve.

These functions could be done in-house or contracted out, either in whole or in part.

Potential subcontractors for DSM portfolio management include:

- another wires company;
- an affiliate;

- a private sector entity (e.g., Enbridge Gas Distribution, Johnson Controls, Union Gas); or
- a joint venture (e.g., a DSM entity created by the Electricity Distributors Association, the Ontario Energy Association or the Canadian Energy Efficiency Alliance).

Hydro One and Ontario's 7 largest municipally-owned LDCs serve 67% of Ontario's electricity consumers; whereas the 44 smallest LDCs serve 5% of the province's electricity consumers. Therefore it is expected that most of the smaller LDCs will contract out their DSM activities in order to achieve economies of scale and thereby increase their SSM award (see Section 5.2.1.5).

Hydro One would be designated as default program management and delivery agency for all Ontario electric utilities. If a utility did not want to have a DSM role (or to contract it out), Hydro One would automatically become the DSM agency for the utility's customers and would be accountable to the OEB. Under this option, the full SSM reward (see section 5.2.1.5) would accrue to Hydro One.

Alternative 1. , Hydro One could become the default supplier only if a utility was unable to take on the DSM function or to carry it out effectively. Another possible alternative could be that only smaller wires companies (based on a threshold set by the OEB) would be eligible to opt out of DSM, using Hydro One as the default supplier.

Alternative 2. All wires companies would be required to develop their own DSM programs or contract them out.

Where DSM responsibility is defaulted to Hydro One, the wires companies would be required to facilitate Hydro One's delivery of DSM by providing customer information, allowing Hydro One DSM bill stuffers etc. It is recognized that there may be possible issues associated with this arrangement arising from the Federal Personal Information Protection and Electronic Documents Act.

5.2.1.2 Program budget and funding

The DSM budget would be based on a uniform baseline charge per kWh collected from all end users (e.g., 0.3 cents per kwh would provide an annual province-wide DSM budget of approximately $450 million assuming Ontario's total electricity consumption is approximately 150,000 Gwh). The charge (which may rise each year) would be determined every 3 years by OEB. Utilities would be able to apply for a higher charge, in order to more aggressively pursue cost-effective energy conservation. The budget would be collected as a part of the revenue requirements of wires companies from all end users.

5.2.1.3 Lost Revenues Adjustment Mechanism (LRAM)

Each wires company that has a DSM program would have a symmetrical LRAM to ensure that its energy conservation and efficiency programs do not reduce its total wires revenues. If an LDC defaults to Hydro One, it will not receive an LRAM. To remove corporate disincentives, Hydro One will obtain an LRAM for both its distribution and transmission revenues for the DSM it delivers. The LRAM would be cleared annually, however for small wires companies with 3 year audit cycles (see below), the annual LRAM clearance will be considered an interim clearance subject to true up based on the audit.

Once DSM impacts grow sizeable (i.e. after an initial period of 2 or 3 years) the LRAM should be a variance account (i.e. DSM should be forecast in the load forecast and LRAM only picks up the variance from forecast).

5.2.1.4 Demand Side Management Variance Account (DSMVA)

Each utility would have a DSMVA to ensure that unspent DSM budget dollars are returned to its customers and that the utility can recover DSM overspending (so long as it is TRC cost-effective, up to 20% of total DSM budget) from its customers. The DSMVA would be cleared annually, subject to true up post audit.

5.2.1.5 Shared Savings Mechanism (SSM)

Description

Each utility would be eligible for an annual incentive reward equal to a fixed percentage (e.g., 2%) of the net present value of the TRC benefits achieved by each year's DSM programs. This shared savings mechanism (SSM) would be distinct from the utility allowed return on equity for supply-side rate base.

The fixed percentage of TRC would be set by the OEB at a level that is deemed adequate to incent aggressive and cost-effective DSM. The incentive rate can be reconsidered as part of the tri-annual PBR process. The Board may also consider thresholds, below which no incentive is awarded, at that time. Additionally, a utility/intervener could ask the OEB to establish a different or more sophisticated incentive for a specific utility.

An appropriate incentive will motivate wires companies to aggressively and cost effectively implement DSM programs that will reduce their customers' energy costs. Moreover, the appropriate incentive will not lead to an undue increase in the wires companies' after-tax return on equity.

Specifically, the appropriate SSM incentive rate will be a function of:

- the DSM budget;
- the expected ratio of the net present value of TRC benefits to utility DSM spending;
- the wires companies' marginal income tax rate; and
- the total common equity of Ontario's wires companies.

For example, according to Chris Neme, the ratio of Enbridge's NPV of TRC benefits to utility spending on DSM varied from 5.5 to 8.3 between 1999 and 2002. Assuming an electric DSM budget of $450 million per year, these ratios imply TRC benefits of $2.475 billion to $3.735 billion. Assuming a 2% shareholder incentive rate, the SSM payments would be $49.5 million to $74.7 million. Whether these incentives are too high or too low depends on the impact they will have on the after-tax return on equity of the Ontario wires companies. Therefore to determine the appropriate SSM incentive rate the Board must also know the total common equity of Ontario's wires companies and their marginal income tax rate.

Under this model, there will be no incentive to pursue DSM programs that are cost-effective to society but are not in the financial self-interest of customers (e.g. where externalities are large).

For small utilities with a three year audit cycle (but annual incentive clearance), the incentive is collected in rates but all or part (e.g. 50%) of the incentive payment could be held back pending audit.

5.2.1.6 Avoided Costs

The OEB would be responsible for determining the long run avoided costs for generation, transmission, distribution and losses to be used in all program evaluations and audits. The OEB would retain experts to develop these values based on information including:

- generation cost forecasts from IMO;
- extrapolated transmission avoided costs and distribution avoided costs based on historical correlation of capital and operations spending with long-term increases in capacity requirements; and
- marginal time differentiated losses provided by the IMO and EDA.

These long run avoided cost values would be updated periodically.

Wires companies with unique avoided costs (due to specific local constraints) could seek to include those costs in their program evaluations, subject to audit. The OEB may wish to consider a threshold above which OEB approval is required for significant avoided cost changes.

5.2.2 Identify & screen opportunities (portfolio management)

Wires companies would be responsible for all aspects of DSM portfolio management, including the identification and screening of program opportunities. These functions could be done in-house or contracted out, either in whole or in part, subject to compliance with the Affiliate Relationship Code. In all cases, the wires companies would remain accountable to the OEB for their DSM programs.

Potential subcontractors for DSM portfolio management include:

- another wires company;
- an affiliate;
- a private sector entity (e.g., Enbridge Gas Distribution, Johnson Controls, Union Gas); or
- a joint venture (e.g., a DSM entity created by the Electricity Distributors Association, the Ontario Energy Association or the Canadian Energy Efficiency Alliance).

Wires companies may choose to split the incentive reward (SSM) with any subcontractor(s).

5.2.3 Design & develop criteria

Consistent with the E.B.O 169-III guidelines for natural gas, the OEB would set the following program selection and portfolio management guidelines for electric DSM:

- DSM programs must reduce electricity consumption for a given energy service need (e.g. cold beer, hot shower).
- DSM programs must pass the Total Resource Cost Test (i.e. the net present value of all pecuniary costs and benefits to all parties must result in a net benefit). The OEB will set the avoided costs to be used in TRC calculations (see section 5.2.1.6).
- Annual DSM portfolio must not cause an undue rate increase.
- DSM spending should be proportional to DSM revenue across broad rate classes (residential, general, and industrial).

Unlike the current gas DSM model, wires companies will not be required to submit DSM plans for approval in advance of implementation.

The positive TRC requirement ensures that the programs are in the economic self-interest of customers and have an overall societal benefit from a financial point of view. Programs that pass the Societal Cost Test (TRC Test plus monetized externality values), but fail the TRC Test, will not be pursued.

5.2.4 Deliver activities

Wires companies would be responsible for delivering DSM programs. Similar to portfolio management, these functions could be performed in house or contracted out in whole or in part. For example, a wires company may choose to deliver some DSM programs using its own staff while contracting out other programs to third parties.

5.2.5 Monitor and evaluate activities

Each year, the wires companies would be responsible for delivering a DSM evaluation report to the OEB. The production of this report could be done in house or contracted out by the wires company. Where one DSM Portfolio Manager acts for several wires companies a joint evaluation could be provided. Evaluation reports would be published and available to interveners with suitable excision to protect customer confidentiality.

The evaluation report would include the following calculations related to the total DSM portfolio:

- Annual kWh and peak kW saved
- Annual kwh and peak kw saved, as percentage of the utility's total kWh delivered and peak demand respectively, broken-out according to major customer classes (e.g. residential, commercial/institutional, industrial)
- Net present value of TRC benefits
- Net present value of TRC benefits per total kWh delivered, broken-out according to major customer categories;
- Actual DSM expenditure
- Actual DSM expenditure per total kwh delivered, broken-out by major customer categories.

Additionally, the evaluation report would include a description and relevant statistics for each DSM program, including:

- target market
- number of participants
- dollars spent per participant
- electricity savings achieved

The evaluation reports would be audited by an independent auditor hired by the OEB (See section 5.2.6) and would act a primary resource for the meta-evaluation of the overall DSM framework by the OEB.

5.2.6 Audit

The OEB would be responsible for the auditing process. The DSM evaluation reports would be audited by an independent external auditor, retained and funded by the OEB, with assistance from a small advisory audit committee. The OEB would appoint and fund the small multi-stakeholder audit advisory committee (e.g. 1 Board Staff and 3 interveners). The costs for the auditor and advisory committee would be assessed against all the wires companies and recovered in their rates.

Large DSM portfolios would be audited annually, whereas smaller portfolios would undergo audits covering a multi-year period at least every three years. Portfolios would be considered ‘large' (i.e. require an annual audit) if the SSM, budget or LRAM exceeds predetermined financial thresholds set by the OEB.
The OEB may choose to conduct spot audits. Audit reports would be made publicly available.

The principles and the terms of reference for the audit should be established and standardized to the greatest extent possible at the beginning of the process, i.e., before program delivery begins, to avoid after-the-fact dispute over the auditor's role and findings, and to ensure a timely and streamlined audit process. Stakeholder input should be considered in the establishment of the audit principles and terms of reference.

Where the auditor finds uncertainty in inputs or measurement, the auditor shall provide suitable values to enable clearance of the variance accounts. Avoided cost will have already been determined on a provincial basis (see section 5.2.1.6). If any party does not accept the findings of the audit it could seek to challenge that finding before the OEB. The OEB would determine the appropriate process for such appeals (e.g. written hearing, leave required, constrained oral hearing, or generic proceeding) depending on the materiality, the nature and frequency of such appeals and the Board's resources.

5.3 Meta Evaluation

The OEB will annually publish a set of statistics about the utilities' DSM programs, based on the audited evaluation reports. This process will provide greater transparency, will motivate utilities to aggressively pursue best practices and will provide the OEB with data for the meta-evaluation of the overall DSM framework in Ontario. The statistics published for each utility will include:

- Annual kwh and peak kw saved;
- Annual kwh and peak kw saved as a percentage of the utility's total kwh delivered and peak demand respectively, broken-out according to major customer classes (e.g. residential, commercial/institutional, industrial);
- Net present value of TRC benefits;
- Net present value of TRC benefits per total kwh delivered and broken-out according to major customer categories;
- Actual DSM expenditure; and
- Actual DSM expenditure per total kwh delivered and broken-out by major customer categories
- Compendium of programs offered in Ontario with relevant statistics (aggregated where the same program is offered by more than one wires company) to serve as a reference for all DSM stakeholders.

The OEB should also publish comparable statistics with respect to Enbridge Gas Distribution's and Union Gas' DSM programs.

If the statistics reveal that utility DSM programs are not cost-effective, the OEB can cease approving DSM budgets for the utilities.

5.4 Needed Changes to Foundation

Implementation of this DSM model may require consideration of and/or changes to market foundations, such as:

- Rates: In order for utilities to collect a uniform charge from end users, each LDC rate order would have to be amended. Under the current process, this would mean that each LDC would have to apply to the

Minister of Energy for approval to go to the OEB to amend their rate order. A possible mechanism for streamlining this process could be for the Minister to pass a regulation which amends all the LDC rate orders to include a uniform per kwh DSM charge.

- OEB practices/procedures. The OEB would have to develop new practices and procedures to fulfil their new responsibilities under this model, such as coordinating the auditing process, setting avoided costs for TRC calculation, issuing guidelines, dealing with issues brought to the OEB for resolution.
- Electricity Distribution Rate Handbook. The handbook currently indicates that DSM will not be addressed until second generation PBR. Adoption of this model will require amendment of the handbook to describe the adopted DSM framework and the guidelines that will apply to the wires companies. Regardless of the PBR model that may be adopted by the OEB in the future, DSM should be treated independently.
- Distribution System Code. Code would need to be amended to allow LDCs to aggregate system load for DR purposes.
- Affiliate Relationships Code would need to be amended to ensure that there are clear and transparent rules in place for an affiliate subcontracting to the LDC specifically for DSM activities.
- New regulations. e.g. requiring and empowering Hydro One to act as default DSM provider, where applicable.
- A regulation may need to be passed to confirm that the promotion of DSM and DR is a distribution activity under section 71 of the OEB Act.

5.5 Market Transformation, Demand Response and Load Aggregation

5.5.1 Market transformation

Under this model, market transformation activities (i.e. province wide DSM programs aiming to transform the market share of a particular technology) could be pursued by:

- A single utility (or its third-party delivery agent)
- Jointly, by several agencies (or their third-party delivery agencies)
- One or more portfolio managers

In order to avoid conflicting market transformation programs and to enable multi-utility participation, wires companies would be required to notify the OEB and other wires companies of any proposed market transformation program. If there is a resulting conflict, which the wires companies cannot resolve, the matter can be addressed in the context of the application to the OEB.

The SSM would motivate utilities to pursue joint and/or third party delivery if that option is expected to yield the greatest net TRC benefits. Wires companies would be able to apply to the OEB for specific market transformation incentive(s) (e.g. specific, multi-year reward for achieving a particular result for a particular end-use measure).

Because market transformation programs benefit participants throughout the province it is appropriate for the OEB to facilitate joint wires company participation (so budget and shareholder incentive payment is charged to a larger group of customers). Successful market transformation programs can help to make higher legally-binding minimum energy efficiency standards a pragmatic policy option for governments. The Ministry of Energy is responsible for developing minimum energy efficiency standards for energy consuming appliances and equipment in the province of Ontario.

5.5.2 Load Aggregation

Utilities would be permitted to aggregate loads to provide demand response resources to IMO (e.g. water heater control program).

5.5.3 Demand Response

The primary responsibility for developing DR initiatives and incentives would fall upon the government or its appointee. Utilities would be permitted to participate in those programs or opportunities. Specifically, the government would:

- evaluate DR options utilizing a societal financial point of view
- pay for load reduction in view of the societal collateral benefits (i.e. the value of reduced peak prices to all market participants).
- guarantee program life for a suitable period to enable wires companies and others to make cost-effective capital investments needed for participation (e.g. Metering where appropriate)
- the IMO would implement DR settlement
- IMO would be required to utilize statistical proxies to enable aggregated retail participation in DR where metering costs are not warranted.

5.5.4 Gas and electric symmetry

This DSM model retains a high level of inter fuel symmetry, while recognizing that absolute symmetry may not be possible (or desirable) due to intrinsic and historical differences between the gas and electric industries in Ontario, such as:

- natural differences in peak versus energy aspects of the commodities
- experience operating DSM programs
- the number of LDCs in Ontario
- relative frequency of utility specific gas rate cases versus relative infrequency of utility specific electric rate cases

5.6 Pros and Cons

Pros of OEB - Wires Framework

Effectiveness

+ wires companies understand the local market participants and conditions, and could tailor selection and design of programs accordingly;
+ the accountability for DSM by multiple wires companies will lead to more

diversity and innovation than would be provided by a single monopoly agency;

+ wires companies have an existing business relationship with channel partners including local businesses and with all electricity consumers in their franchise areas;
+ there are economies of scale/scope with respect to the delivery of energy efficiency programs given that wires companies are already distributing/promoting electricity (e.g. use of bill envelope);
+ Wires companies are trusted sources of energy information and have established communications channels with customers;

Targeting

+ LDC centric programs, dealing with territory needs can more easily be addressed.
+ LDCs are more familiar with local market issues.
+ Municipal needs may be more easily incorporated into LDC DSM/DR planning and delivery and coordinated politically.

Accountability

+ This model leaves those functions that are necessarily delivered centrally with the OEB, i.e., responsibility for setting the overall DSM budget, portfolio guidelines, avoided costs, and for hiring the auditor. This ensures that the necessary centralized functions will be managed by an established agency, allowing for a faster start-up.
+ wires companies are already accountable to the OEB for their performance;
+ multiple wires companies will create benchmarks for comparison and accountability, leading to 'competition' and higher levels of performance
+ wires companies are accountable to local constituencies which in turn promotes higher standards of service;
+ It also provides access for citizens to have input into DSM design and delivery at the local level.
+ As well, since the OEB has well established procedures for public input, this model ensures that stakeholders will have an opportunity to comment on the province-wide aspects of DSM.

Public policy

+ Since wires companies are owned by the local municipality, accountability for DSM with the wires companies provides the opportunity for the local community to consider DSM as part of their overall strategic plan.

Competition

+ there is potential for competition among delivery agents and portfolio managers serving wires companies;

Regulatory burden

+ Commercialization of the wires companies makes them amenable to incentive based regulation.

Financial viability of regulated monopolies

+ wires companies could recover their costs from all the beneficiaries;
+ The OEB's experience with gas DSM demonstrates that a SSM is necessary to motivate utilities to aggressively and cost-effectively promote DSM.
+ For example, from 1995 to 1998 Enbridge had no incentive to aggressively promote energy conservation and efficiency. As a result, Enbridge failed to achieve its annual DSM targets by 19% to 70% during this period.
+ In 1998 the OEB established a SSM for Enbridge that commenced in 1999. As a result, Enbridge exceeded its annual DSM targets by 21% to 67% from 1999 to 2001. (Independent audits of Enbridge's 2002 and 2003 results have not yet been completed.)
+ Unlike Enbridge, Union Gas does not have an SSM. As a consequence, the positive impact of an SSM can also be seen by comparing Enbridge's and Union's forecast DSM savings for 2004. Despite the fact that Union Gas is Ontario's largest natural gas utility, its DSM targets for 2004 are dramatically lower than those of Enbridge. Specifically, the forecast energy cost savings of Union's DSM programs are 56% less than those of Enbridge ($79.4 million for Union versus $180.4 million for Enbridge).
+ A well designed SSM is in the financial self-interests of ratepayers since it will lead to the achievement of incremental energy cost savings that are dramatically greater than the magnitude of the shareholder incentive. That is, it will lead to a net reduction in the energy bills of the utilities' customers. For example, Enbridge's DSM programs from 1995 to 2004 are forecast to reduce their customers' bills by more than $680 million; whereas the total SSM payments to date have been $12.9 million.

Cons of OEB - Wires Framework

Effectiveness

- Allocation of efforts by customer class may reduce overall impact.
- Utilities may have a disincentive to lobby for better efficiency standards, as improved standards would erode the potential size SSM result.
- Potential for difficulties for programs spanning LDC boundaries.
- Potential loss of economies of scope and scale in programs, research and data collection and redundancy of program design efforts.
- More difficult to coordinate initiatives with those of other Government departments.
- Market transformation initiatives would require coordination.
- Requires SSM, LRAM and DSMVA whereas within a competitive model, the incentive to the participants would be the realization of profits.

Accountability

- Permanent structure -- no provision for sun setting.
- Could inflate rates of return.

Regulatory Burden

- More resources may be required for regulatory oversight if multiple LDCs actively participate in portfolio management.
- LDC driven DSM appears to necessitate the need for various incentive mechanisms such as the LRAM and SSM; the computation and audit of which, historically in the gas business, has been full of discourse, subjectivity, and inefficient to manage.
- The model does not penalize the LDC for non-compliance and/or under-performance.
- There would be tendency to overstate results on the part of the LDCs
- Factoring attribution factors into results would be difficult.

Universality / Consistency

- Lack of uniformity across the province, no development of common standards.
- Probable lack of universal access to all programs
- Difficult for customers that have energy services needs that cross franchise/distributor boundaries. This drawback occurs in Option C also.
- It would be more difficult to achieve public policy goals.
- Delivery lines for programs are drawn against LDC territories and not based on demographic, market and regional realities.

Competition

- Selection of project types not competitive.
- May come between customers of power retailers.
- Goes against the intent that LDCs are "wires only" entities and places them in potentially a competitive position with the private sector. Transparency and fairness may be questioned where utility affiliates are allowed to compete with private sector delivery agents.
- Private sector delivery agents are faced with interfacing with multiple LDCs and multiple programs each with different rules and application procedures adding significantly to the delivery costs of projects for customers.
- Greater diversity of DSM programs would be achieved through open competition in the DSM arena. A "Wires or LDC based framework" might naturally lead to a handful of the larger LDCs determining their own programs and other LDCs in the province following suite on the same type of programs. This would limit program diversity.
- With DSM programs limited to the LDCs, customer choice would also be eliminated.

Delay

- Slow start-up process will be expected as most LDCs lack capability and expertise in DSM/DR.

Financial viability of regulated monopolies

- Model assumes that utilities are willing and able to undertake the comprehensive responsibility for doing DSM and/or contract out that responsibility.

- This model may place an increased and unwanted burden on Hydro One - A mandatory default role for Hydro One puts HONi in conflict with relevant LDCs and may inflate HO costs.
- Puts LDCs in defensive positions simply to maintain existing revenues, since if they default there will be no LRAM. Wrongly assumes that revenue protection is unnecessary or undeserved if the utility doesn't do DSM itself.
- Some LDCs have absolutely no experience developing programs so they would have to increase their resources to do so. This would represent another cost for end-use consumers.

6 GENERAL ISSUES

6.1 Efficiency and Energy Use

Some Demand-Side Management programs may increase energy use. For example, the widely publicized availability of financial incentives for some efficiency measures may retard private investments in other efficiency measures, while intelligent consumers wait to receive incentives. Other consumers, who have curtailed their energy consumption in order to save money or to minimize environmental or social harm, may increase their consumption after DSM programs increase the efficiency of their energy use – for a simple example, after a 100-watt incandescent bulb is replaced with a 23-watt compact fluorescent, a light that was on for minutes a day may be left on for hours a day. Or the new owner of a super-efficient gas furnace may turn up the thermostat.

An entire incremental and optional or elective way of consuming energy – gas or electric fireplaces, radiant outdoor space heaters, etc. – may gain a much greater place in the market if it carries a sticker or label that assures consumers that it is "efficient". Promoters of energy-consuming hardware or of energy itself may find creative ways to build sales – and increase energy consumption – by piggy-backing their efforts on the well-meaning efforts of others (or their own colleagues) to decrease energy consumption.

In the field of natural-gas DSM, there have been numerous overlaps between load-building "marketing" activities and load-decreasing "DSM" activities. For example, consumers of electric heat can be approached by staff of a gas LDC to convert to gas heat and do so by installing a high-efficiency gas furnace. The approach – even if it happened in one visit – was essentially considered to be two approaches: one by the marketing department to achieve fuel-switching and load building, and a second by the DSM department to raise the efficiency of the furnace from the average furnace on the market to the high-efficiency furnace. These overlaps have generally been openly disclosed by the gas LDCs, and have generally been tolerated or even applauded by stakeholders, who generally see gas consumption as more socially desirable than electricity consumption. If similar overlaps occur in electrical DSM programs – as we believe is likely – the impact on public well-being will almost certainly be negative.

The Gas Research Institute has issued a report concerning trends in per-household natural-gas usage in many jurisdictions in northeastern North America. The report indicates that per-household natural-gas usage has been steadily declining throughout the region and throughout the study period, at an average rate of 1.2% per year. During that same study period, per-household natural-gas usage in an area of Ontario that is generally considered to have aggressive and effective gas DSM programs declined significantly more slowly than average.

Any "feedback" and "meta-analysis" of future DSM policy frameworks may be well informed by overall consumption measurements comparable to that of the GRI study in addition to those generally accepted in DSM/DR monitoring and evaluation protocols.

6.2 Local Integrated Resource Planning for Local Distribution Companies

Some Advisory Group members suggested that the LDC should not have a role in delivering DSM except for system augmentation requirements at the LDCs local level. This is a form of Local Integrated Resource Planning (LIRP). The LDCs should take on an open planning process where supply and demand side options are evaluated on an equal basis and a least cost approach used for determining which options are implemented. DSM/DR options should be called upon with sufficient lead times to enable them to have the desired impacts – i.e., delaying or alleviating the need for system augmentation. Calling for DSM/DR in the same time frame that supply side system augmentation would occur (usually at the last minute) will rarely allow DSM/DR to compete. The planning horizon must be of a sufficiently long period (5 years) to enable the DSM/DR suppliers to consider and evaluate options to alleviate the constraints. The LDC should be rewarded under the PBR mechanism for choosing the least cost planning alternative.

6.3 Implications of Reliance on the Total Resource Cost Test

The use of TRC rather than SCT for screening and the incentive will lead to a choice of measures that do not optimally reduce societal costs. Even a conservative estimate of the monetized value of externalities would be better than treating the environment and public health as having no value. One possible compromise would be that the TRC should count any value generated in tradable emissions regimes that may be put in place pursuant to the Kyoto Accord or otherwise as this will be a recognized value generated by a market resulting from broader government action.

6.4 Financial Viability of LDCs

Consideration of DSM and DR raise concerns with respect to the financial viability of LDCs, stranding of assets and potential for additional cost burden to consumers. In the OEB/LDC Model Framework, LDCs are compensated and rewarded for their DSM activities. In the Central Model Frameworks, LDCs are not expected to carry out DSM activities, but are expected to propose distribution rates which account for the effects of DSM and DR in the market place.

It has been recognized that LDC’s are valuable partners in the delivery of DSM due to their customer relationships. Without revenue protection LDC’s would be financially harmed by DSM efforts. Moreover, a perverse incentive for load building efforts is created in order to compensate for lost revenue; this is an activity that electric LDC’s currently do not engage in. Such an outcome would be unwanted and counterproductive in a period of short supply.

Depending on the level of financial impact on the LDC, credit ratings may also be affected. As a minimum, credit rating agencies would regard revenue erosion from DSM as a negative influence on the LDC’s credit ratings. If the effects are significant enough, or if coupled with other negative factors, a credit downgrade may result. This would lead to higher borrowing costs, and could also trigger a substantial increase to the LDC's prudentials posted with the IMO.

The LRAM mechanism, together with the annual load forecast, is used by the gas companies to maintain revenue levels. This mechanism may not be easily adaptable to electric LDC's due to multi-year PBR plans, and two added dimensions which did not exist under gas DSM.

First, a large portion of distribution revenues are derived from a second volumetric measure, which is demand (kW or kVA). Secondly, DR programs are to be developed in conjunction with DSM, which are designed to shift kWhs from peak times rather than promote energy efficiency or conversation. All four elements (DSM, DR, kWh, kW) are interrelated, making the LRAM calculation significantly more complex than found in gas.